Supreme Court, U.S.
FILED

D4186 8 MAY 15 1995

No. ——OFFICE OF THE CLERK

IN THE

Supreme Court of the United States

OCTOBER TERM, 1994

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

PETITION FOR A WRIT OF CERTIORARI

EDWARD S. FINLEY, JR.*
JAMES L. HUNT
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

WILSON - EPES PRINTING CO., INC. - 789-0096 - WASHINGTON, D.C. 20001

38 pp

QUESTIONS PRESENTED

1. Whether the Supremacy Clause of the United States Constitution permits one state in setting an electric utility's retail rates to reject wholesale costs the utility was ordered to incur pursuant to a second state's determination of such wholesale costs, the second state's determination being entirely an exercise of authority over wholesale rates delegated to it by Federal law.

2. Whether the Commerce Clause of the United States Constitution permits the rejection in one state's retail rate proceeding of wholesale costs an electric utility was ordered to incur pursuant to a second state's exercise of delegated Federal authority.

PARTIES BELOW

North Carolina Power was the Appellant in Case No. 230A93 in the Supreme Court of North Carolina.

The Public Staff of the North Carolina Utilities Commission was an Appellee in Case No. 230A93 in the Supreme Court of North Carolina.

The Attorney General of North Carolina, Michael F. Easley, was an intervenor in the proceeding and an appellee in Case No. 230A93 in the Supreme Court of North Carolina.

RULE 29.1 STATEMENT

North Carolina Power is the North Carolina operating division of Virginia Electric and Power Company in North Carolina. Virginia Electric and Power Company is a wholly-owned subsidiary of Dominion Resources, Inc. Virginia Electric and Power Company has no non-wholly-owned subsidiaries.

TABLE OF CONTENTS

	Page
QUESTIONS PRESENTED	i
PARTIES BELOW	ii
RULE 29.1 STATEMENT	ii
TABLE OF AUTHORITIES	vi
OPINIONS BELOW	1
JURISDICTION	1
CONSTITUTIONAL AND STATUTORY PROVISIONS	2
STATEMENT OF THE CASE	3
A. Introduction	3
B. Background:	
1. The Virginia Arbitration	8
2. The North Carolina Utilities Commission Proceedings	11
3. The North Carolina Supreme Court's Decision	14
REASONS FOR GRANTING THE PETITION	16
I. PURPA PREEMPTS NORTH CAROLINA'S APPLICATION OF ITS STATUTES	16
A. This Case Raises Important Federal Issues	16
B. The Decision of the North Carolina Supreme Court Is in Conflict With This Court's Decisions	19

TABLE OF CONTENTS—Continued

Page

II. NORTH CAROLINA'S RULINGS VIOLATE THE COMMERCE CLAUSE 28

CONCLUSION 30

APPENDICES *

APPENDIX A

Opinion of the Supreme Court of North Carolina (December 9, 1994) 1a

APPENDIX B

Order of the Supreme Court of North Carolina (February 15, 1995) 22a

APPENDIX C

Order of the North Carolina Utilities Commission (February 26, 1993) 24a

APPENDIX D

Order of the Federal Energy Regulatory Commission (February 28, 1990) 140a

APPENDIX E

Order of the Virginia State Corporation Commission (February 26, 1988) 164a

APPENDIX F

Decision on Pricing Issue, Thomas P. Harwood, Jr., Virginia State Corporation Commission (April 27, 1988) 169a

---

* The Appendices have been separately bound pursuant to Rule 14.1(k).

TABLE OF CONTENTS—Continued

Page

APPENDIX G

Interim Order of the Virginia State Corporation Commission (May 27, 1988) 175a

APPENDIX H

Award and Final Order of the Virginia State Corporation Commission (September 30, 1988) 184a

APPENDIX I

Order of the Virginia State Corporation Commission Ending Proceedings (November 18, 1988) 191a

APPENDIX J

Excerpts from the Federal Power Act, 16 U.S.C. §§ 824, 824a-3 ..... 194a

APPENDIX K

Excerpts from Regulations under the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. Part 292 (1987) 198a

APPENDIX L

Order of the Virginia State Corporation Commission (January 11, 1983) 203a

APPENDIX M

Final Order and Order Denying Petition for Reconsideration of the Virginia State Corporation Commission (November 15, 1985; December 6, 1985) 213a

APPENDIX N

Rule 29.1 Statement 233a

TABLE OF AUTHORITIES

CASES — Page

CTS Corp. v. Dynamics Corp. of America, 481 U.S. 69 (1987) 28
Edgar v. MITE Corp., 457 U.S. 624 (1982) 28
Federal Energy Regulatory Comm'n v. Mississippi, 456 U.S. 742 (1982) 20, 23, 24, 25
Federal Power Comm'n v. Southern California Edison Co., 376 U.S. 205 (1964) 20
Freehold Cogeneration Associates, L.P. v. Bd. of Regulatory Comm'rs of New Jersey, 44 F.3d 1178 (3rd Cir. 1995) 17
Healy v. Beer Institute, Inc., 491 U.S. 324 (1989) 28
Jersey Central Power & Light Co. v. Federal Power Comm'n, 319 U.S. 61 (1943) 19
Lake Erie & Western R.R. Co. v. Public Utils. Comm'n, 249 U.S. 422 (1919) 2
Middle South Energy, Inc. v. Arkansas Public Service Comm'n, 772 F.2d 404 (8th Cir. 1985), *cert. denied*, 474 U.S. 1102 (1986) 29
Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988) 6, 7, 14, 15, 19
Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986) 6, 7, 14, 15, 19, 21, 22, 23
New England Power Co. v. New Hampshire, 455 U.S. 331 (1982) 28
Philadelphia v. New Jersey, 437 U.S. 617 (1978) 29
Public Utilities Comm'n of Rhode Island v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927) 4, 19
Smith Cogeneration Management, Inc. v. Oklahoma Corp. Comm'n, 863 P.2d 1227 (Okla. 1993) 18
Wilson v. Harlow, 860 P.2d 793 (Okla. 1993), *cert. denied*, —— U.S. ——, 114 S. Ct. 1067, 127 L.Ed.2d 386 (1994) 17

ADMINISTRATIVE DECISIONS

Connecticut Light & Power, 70 F.E.R.C. ¶ 61,012 (1995) 17
Doswell Limited Partnership, 50 F.E.R.C. ¶ 61,251 (1990) 23
New York State Electric & Gas Co., 71 F.E.R.C. ¶ 61,027 (1995) 17

TABLE OF AUTHORITIES—Continued

UNITED STATES CONSTITUTION — Page

Art. I, Sec. 8, cl. 3 (Commerce Clause) ..... 2, *passim*
Article VI, cl. 2 (Supremacy Clause) 2, 7, 18, 22, 25

STATUTES

Federal Power Act, 16 U.S.C. §§ 791-825 3
16 U.S.C. § 796(17)(A) 4
16 U.S.C. § 796(18)(A) 4
16 U.S.C. § 824 19
16 U.S.C. § 824(a) 2
16 U.S.C. § 824a-3 ..... 2, 4, 6
16 U.S.C. § 824a-3(a) 2, 18, 20
16 U.S.C. § 824a-3(f)(1) 8
28 U.S.C. § 1257 2
28 U.S.C. § 1257(a) 2

REGULATIONS

18 C.F.R. § 292.101(b)(6) 5
18 C.F.R. § 292.203 4
18 C.F.R. §§ 292.301-308 3
18 C.F.R. § 292.303(a) 3
18 C.F.R. § 292.304 ..... 10, 17
18 C.F.R. § 292.304(a)(2) 5
18 C.F.R. § 292.304(d)(2) 9, 27
18 C.F.R. § 292.401 18
18 C.F.R. § 292.401(a) 3, 6, 9

MISCELLANEOUS

William W. Berry, *Competition in the Electric Industry: The Influence of PURPA, PUHCA, and Transmission Access*, ABA Section of National Resources Law Report (Fall, 1991) 16
124 Cong. Rec. H35002 (daily ed. October 10, 1978) 20
Jim Rossi, *Making Policy Through the Waiver of Regulations at the Federal Energy Regulatory Commission*, 47 Admin. L. Rev. 255 (1995) 17

IN THE

Supreme Court of the United States

OCTOBER TERM, 1994

No. ———

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

PETITION FOR A WRIT OF CERTIORARI

Petitioner North Carolina Power respectfully requests that a Writ of Certiorari issue to review the judgment of the Supreme Court of North Carolina entered in Case No. 230A93 on December 9, 1994.

OPINIONS BELOW

The opinion of the Supreme Court of North Carolina (App. 1a-21a) is reported at 338 N.C. 412 (1994) and 450 S.E.2d 896 (1994). The order of the North Carolina Utilities Commission dated February 26, 1993 (App. 24a-139a) is reported at 83 N.C.U.C. Rep. 271 (1993) and 142 P.U.R.4th 117 (1993).

JURISDICTION

The Supreme Court of North Carolina issued its opinion on December 9, 1994, and denied North Carolina Power's Petition for Rehearing on February 13, 1995

(App. 22a-23a). This Court has jurisdiction under 28 U.S.C. 1257(a).[1]

CONSTITUTIONAL AND STATUTORY PROVISIONS

The United States Constitution, Article VI, cl. 2.

> "This Constitution, and the Laws of the United States which shall be made in Pursuance thereof . . . shall be the supreme Law of the Land; and the Judges in every State shall be bound thereby, any Thing in the Constitution or Laws of any State to the Contrary notwithstanding."

The United States Constitution, Article I, Sec. 8, cl. 3.

> "The Congress shall have Power . . . To regulate commerce with foreign Nations, and among the several States."

The Federal Power Act, 16 U.S.C. § 824(a) (1988).

> "It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation relating to generation to the extent provided in . . . this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest."

The Federal Power Act, 16 U.S.C. § 824a-3(a) (1988).

---

[1] The Supreme Court of North Carolina upheld the Commission's ratemaking order against North Carolina Power's challenge that the order violates North Carolina Power's rights under the Supremacy Clause, Article VI of the United States Constitution, and the Commerce Clause, Art. I, Sec. 8, of the United States Constitution and the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 824a-3. State ratemaking orders are considered to be state statutes within the meaning of 28 U.S.C. § 1257. *Lake Erie & Western R.R. Co. v. Public Utils. Comm'n*, 249 U.S. 422, 424 (1919).

> The Federal Energy Regulatory "Commission shall prescribe . . . such rules as it determines necessary to encourage cogeneration and small power produciton . . . which rules require electric utilities to offer to . . . purchase electric energy from such facilities."

Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. § 292.303(a) (1987).

> "*Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with [18 C.F.R.] § 292.304, any energy and capacity which is made available from a qualifying facility: (1) Directly to the electric utility."

Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. § 292.401(a) (1987).

> "State regulatory authorities. Not later than one year after these rules take effect, each State regulatory authority shall . . . commence implementation of [18 C.F.R. §§ 292.301-308]. Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under [18 C.F.R. §§ 292.301-308], or any other action reasonably designed to implement [18 C.F.R. §§ 292.301-308]."

STATEMENT OF THE CASE

A. Introduction

Early in this century Congress recognized the Nation's overriding national interest in the unimpeded flow of wholesale power in interstate commerce. Congress established the Federal Power Commission (now FERC)[2] with exclusive jurisdiction over such interstate transactions because regulation by each affected State had resulted in chaos.[3] Today most of the Nation's new electric power

---

[2] Federal Energy Regulatory Commission.

[3] Congress established the Federal Power Commission in 1935. 16 U.S.C. §§ 791-825 (1988). This action came in response to this

is generated, not by the traditional electric utility companies, but instead by alternative providers like cogenerators and small power producers.[4] Wholesale sales by these alternative providers are made under PURPA,[5] adopted in 1978, not under the original provisions of the Federal Power Act. Congress delegated many of the oversight functions under PURPA to the States that otherwise would be carried out by FERC. As so many of the Nation's wholesale power transactions now take place under PURPA and as the States now play important roles in the Act's implementation, it is imperative that these State administrative functions not be subverted by the chaotic piecemeal oversight that existed before the Federal Power Act was passed.

This case raises important Federal issues under PURPA over the manner in which the States are to administer the Federal decision-making authority Congress has delegated to them. Virginia Power is a multi-state electric utility whose customers reside primarily in Virginia; a much smaller percentage of its customers reside in North Caroline. A serious dispute has arisen between two states, Virginia and North Carolina, over the Federal actions

---

Court's ruling in *Public Utilities Comm'n of Rhode Island v. Attleboro Steam & Electric Co.*, 273 U.S. 83, 89 (1927) (wholesale transactions between utilities in different States are interstate commerce and any State regulation of such transactions was an unlawful burden on interstate commerce).

[4] A "cogeneration facility" is one that produces both electric energy and steam or some other form of useful energy, such as heat. 16 U.S.C. § 796(18)(A) (1988). A "small power production facility" is one that has a production capacity of no more than 80 megawatts and uses biomass, waste, or renewable resources (such as wind, water, or solar energy) to produce electric power. 16 U.S.C. § 796(17)(A) (1988).

[5] The Public Utility Regulatory Policies Act of 1978, 18 U.S.C. § 824a-3 (1988). If a cogeneration or small power production facility meets the technical and ownership criteria developed by the FERC, then it is deemed to be a "qualifying facility" (QF) entitled to the benefits of PURPA. 18 C.F.R. § 292.203 (1994).

taken by Virginia in resolving a dispute between a cogenerator, Ultra Cogen Systems, Inc. (Ultra Cogen), and the utility, Virginia Electric and Power Company (Virginia Power), purchasing its electrical output under PURPA. Virginia, through its State Corporation Commission (VSCC), in 1988 decisions has implemented PURPA by imposing a requirement that Virginia Power purchase 228 megawatts[6] of cogenerated power from Ultra Cogen at $341 per kW per year for the first 15 years of the 25 year term of the contract. The VSCC determined the $341 price to be Virginia Power's "avoided costs" under PURPA, the cost Virginia Power would have incurred but for the purchase.[7] North Carolina, through its North Carolina Utilities Commission (NCUC), in a 1992 State decision, affirmed by the North Carolina Supreme Court, has subsequently reviewed the Virginia Federal decision and determined that Virginia set the price too high. North Carolina has penalized the utility by prohibiting the utility from recovering from North Carolina retail customers a large percentage of the price paid to Ultra Cogen. The disallowance is $1.39 million per year for the 15 year period.

The North Carolina Utilities Commission recognized that the electric utility was being made the sacrificial lamb by the conflicting actions of the two States:

> This Commission also recognizes the position of Vepco. It is "caught in the middle" between our

---

[6] The VSCC orders addressed four plants with a maximum dependable capacity of 57 mW each. At the time of the North Carolina decision, three plants were in operation with a maximum dependable capacity of 62.7 mW each.

[7] A rate for purchase is consistent with Federal law if the rate equals the utility's avoided costs. 18 C.F.R. § 292.304(a)(2) (1994). Avoided costs has been defined by FERC as "the incremental costs of an electric utility of electric energy or capacity or both which, but for the purchases from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (1994).

> decision and that of the Virginia SCC, but that is not unique to this issue. That is an inevitable consequence of doing utility business across state lines.

App. 75a.

North Carolina's collateral attack upon the Virginia Federal decision raises a serious Federal preemption issue. North Carolina's decision squarely conflicts with this Court's decisions in *Nantahala Power & Light Co. v. Thornburg*[8] and *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*.[9] Ultra Cogen's sales of power to Virginia Power clearly are wholesale sales in interstate commerce. Virginia Power includes its purchases from Ultra Cogen within its power supply obtained from other sources, including its own generation and purchases on the interstate power grid. Virginia Power sells power from all of these sources at retail in North Carolina and Virginia, as well as at wholesale to other suppliers in other States through the interstate grid.

Upon the passage of PURPA, Congress carved out an exception to FERC's exclusive jurisdiction over wholesale sales in interstate commerce.[10] Under PURPA, Congress authorized the States to resolve disputes such as the dispute that arose between Ultra Cogen and Virginia Power.[11] As States have no jurisdiction over wholesale sales of power in interstate commerce but for PURPA,

---

[8] 476 U.S. 953 (1986).

[9] 487 U.S. 354 (1988).

[10] The relevant section of PURPA here is Section 210, 18 U.S.C. § 824a-3 (1988), which concerns cogeneration. App. 195a-197a.

[11] State regulators have been required to create and enforce arrangements between wholesale purchasers of electricity and wholesale sellers, including cogenerators. 18 C.F.R. § 292.401(a) (1987). The means of such enforcement "may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart." *Id.* (App. 202a).

and as States are only implementing PURPA when resolving disputes between qualifying facilities and electric utilities under mandatory guidelines promulgated by FERC, the actions exercised by the States in this area are Federal ones and not State ones.

This Court, in its recent *Nantahala* and *Mississippi Power* decisions, cogently has reaffirmed the longstanding principle that once a Federal wholesale for resale rate has been established pursuant to appropriate Federal authority, no State can collaterally attack and undermine the Federally-established rate by refusing to recognize the wholesale costs in establishing retail rates.

The issue before the North Carolina Supreme Court was whether the Virginia Commission's order requiring Virginia Power to buy power from Ultra Cogen, a sale Virginia Power wished to avoid, at a price above the price Virginia Power sought to pay, was the equivalent of a FERC decision establishing wholesale for resale costs for purposes of applying this Court's rulings in *Nantahala* and *Mississippi Power*. If it was, North Carolina was bound by the Supremacy Clause to honor the Virginia decision.

The North Carolina Supreme Court acknowledged this Court's holdings in *Nantahala* and *Mississippi Power* but circumvented the Court's rulings by challenging the Virginia Commission's characterization of its own actions and by reclassifying the price set by Virginia as a price "in excess of avoided cost." Such blatant disregard of this Court's pronouncements by the very court that was reversed in *Nantahala* should not go unaddressed.

The North Carolina court's reclassification of the Virginia Commission's actions to avoid the holdings of this Court in *Nantahala* and *Mississippi Power*, if allowed to stand, will seriously undermine PURPA. The North Carolina court's reclassification has the effect of rendering the Federal decision that established the price a qualify-

ing facility may charge unenforceable beyond the State lines of the State rendering the Federal decision.

By its rulings, North Carolina has ignored the Federal decision of its sister State and has taken steps to shield North Carolina citizens affected by the Federal decision from paying costs that must be borne by the remainder of the utility's consumers in other States. North Carolina's actions, if left unrectified, seriously undermine the Congressional intent that States render Federal decisions in implementing PURPA. If the utility can be "caught in the middle" (App. 75a) as North Carolina asserts, then North Carolina's actions deal a serious blow to the Congressional desire that purchases of power from alternative suppliers like Ultra Cogen be encouraged.

B. Background

1. *The Virginia Arbitration.*

Ultra Cogen sought to develop a number of qualifying facilities (QFs) in the service territory of Virginia Power in Virginia. App. 2a-3a, 62a. Ultra Cogen engaged in unsuccessful negotiations with Virginia Power for the sale of the electrical output from its QFs. App. 62a. Virginia Power was unwilling to pay the price Ultra Cogen proposed. Between November 12, 1987, and December 3, 1987, Ultra Cogen filed petitions before the VSCC pursuant to 16 U.S.C. § 824a-3(f)(1) asking the Virginia Commission to arbitrate this dispute over Virginia Power's obligation to purchase the cogenerated power and the price the utility should pay. App. 63a, 177a.

Before this dispute arose, in January 1983 and November 1985, the VSCC had issued orders stating that it would arbitrate disputes between qualifying facilities and electric utilities who could not agree upon acceptable contractual arrangements. App. 166a, 203a, 213a. These orders were issued to comply with FERC's regulations that State commissions implement PURPA by "undertaking to resolve disputes between qualifying facilities

and electric utilities . . ." 18 C.F.R. § 292.401(a) (1987). App. 166a n.1. Pursuant to these orders, the VSCC undertook to arbitrate the dispute between Ultra Cogen and Virginia Power. By an order issued February 26, 1988, the VSCC designated one of its members, Judge Thomas P. Harwood, Jr., as arbitrator. The pertinent issue in the arbitration was the price to be paid to Ultra Cogen by Virginia Power, as measured under PURPA by Virginia Power's "avoided costs." App. 164a-168a.

At the time of the arbitration, Virginia Power was in the process of implementing a procedure under which it would solicit bids from qualifying facilities so as to establish avoided costs as the lowest acceptable bid, rather than as the projected costs of power from plants the utility would construct itself. App. 173a. This latter method had been the traditional process for determining avoided costs used by Virginia Power and repeatedly accepted by the VSCC as an appropriate method for determining avoided costs. This traditional method was referred to as "administratively determined avoided costs." In its February 26, 1988 order requiring arbitration, the VSCC commented that Virginia Power could solicit bids but that any such solicitations would be specifically subject to the Ultra Cogen arbitration. App. 168a.

Before Judge Harwood, Virginia Power argued that the solicitation procedure would produce avoided costs lower than the administratively determined avoided costs and urged him to determine the avoided costs to be paid to Ultra Cogen through reference to the competitive bids received in a 1988 or alternatively to an earlier 1986 solicitation. App. 173a. Ultra Cogen argued that the avoided costs determined through the competitive bid process could not be used. In order to resolve these differences, the arbitrator looked to FERC rulings and regulations for guidance. App. 171a-173a.

Judge Harwood determined that 18 C.F.R. § 292.304 (d)(2) (1987) allows the qualifying facility to choose

to have the price established at (a) the date the energy is available, or (b) the date on which a legally enforceable obligation is established. The arbitrator determined that Ultra Cogen, through its petition, had selected (b), the date of the legally enforceable obligation, which he determined to be November 12, 1987, the date the first petition for arbitration was filed. App. 171a-172a. Thus, the date for determining avoided costs to be paid Ultra Cogen was specifically decided by Judge Harwood.

Next, Judge Harwood decided whether the basis for determining avoided costs would be administratively determined or determined by reference to competitive bids. App. 172a-173a. Judge Harwood expressly rejected Virginia Power's position that resort should be made to the then upcoming bidding procedure to determine avoided costs.[12] Because he had ruled that 18 C.F.R. § 292.304 required that the price be established on November 12, 1987, Judge Harwood found that "the figures related to Virginia Power's [1988 solicitation] are not known even today, and will not be known for some time. This matter must be resolved now, however, and not at some indefinite future date." App. 173a. Judge Harwood thus ruled that Virginia Power's avoided costs on November 27, 1987, were the costs of constructing and operating Virginia Power's power plant, Chesterfield No. 7, as projected on November 12, 1987. This plant was intended by the Company to be the prototype of any new capacity to be built by the Company through the mid 1990s. App. 172a-173a.

By interim order issued May 27, 1988, the arbitrator identified the capacity cost based on his earlier rulings to be $341.23 per kW per year and ordered the parties to execute contracts incorporating that price. App. 178a-

[12] The VSCC formalized the use of the bidding procedure in its Rules Governing the Use of Bidding Programs to Purchase Electricity from Other Power Suppliers in its Final Order in Case No. PUE900029 (November 28, 1990), almost two years after its Arbitration Order in this proceeding.

179a. On September 30, 1988, the parties submitted the contracts, and on the same date the arbitrator approved them. App. 189a-190a. By order issued November 18, 1988, the VSCC ratified and adopted the arbitrator's determinations. App. 192a. Virginia Power did not appeal that order. Subsequent to the order, three of the Ultra Cogen plants have been completed, and Virginia Power has been buying power from them at the prices required by the VSCC. App. 65a. The annual capacity costs are $64 million. App. 62a.

2. *The North Carolina Utilities Commission Proceedings.*

In 1992 Virginia Power, which operates as North Carolina Power in North Carolina, filed for an increase in its North Carolina retail rates before the North Carolina Utilities Commission. The Commission's Public Staff advocated disallowance of $1.39 million per year of the $2.8 million Ultra Cogen capacity payments allocated to North Carolina.[13] App. 66a.

The NCUC disallowed the $1.39 million. The NCUC recited the history leading to the signing of the Ultra Cogen-Virginia Power contracts including Virginia Power's attempt to persuade the arbitrator to set a lower price. App. 61a-65a. The NCUC noted that at approximately the same time Virginia Power signed the contracts with Ultra Cogen, it was signing contracts with cogenerators whose bids were selected in the 1988 solicitation. Seven of those projects were on line with capacity payments averaging $171 per kW. App. 65a. The NCUC disallowed the difference between the $341 per kW paid

[13] All capacity and energy sold by Ultra Cogen is acquired by Virginia Power in Virginia. Thereafter this power loses its identity and is intermixed with power from all of the Company's other sources of generation. Power Virginia Power sells in North Carolina comes indiscriminately from these combined sources. The percentage of the costs of the combined sources of power charged in North Carolina is determined by allocation factors approved by the North Carolina Utilities Commission.

Ultra Cogen and the $171 per kW average capacity price paid to these seven cogenerators. App. 72a-73a. The NCUC's disallowance was based on its belief that the price to be paid Ultra Cogen should have been based on competitive bids received in the year following the filing of the arbitration. App. 69a, 72a. The VSCC, of course, had rejected the use of competitive bids, which had been put forward by Virginia Power, as being inconsistent with FERC regulations. The NCUC ignored the VSCC justification for rejecting this position and did not address the FERC regulations at issue.

The NCUC stated that although States are to implement PURPA by resolving disputes over the obligation to buy and over price (App. 67a), as had Virginia, FERC did not seek to divest from regulatory agencies of other States the authority subsequently to review cogeneration contracts as part of their regulation of electric utilities. App. 68a. The NCUC noted that FERC regulations suggested that States could authorize prices in excess of avoided costs on the basis of State, not Federal, authority, and that Virginia at one time in the past had authorized a 15% rider above avoided costs (the NCUC, however, recognized that no 15% rider was added to the price paid Ultra Cogen).[14] App. 68a. The NCUC ruled

[14] The NCUC mischaracterized the 15% "rider." Its lone appearance in Virginia was in the VSCC order dated November 15, 1985, in which the VSCC set rates Virginia Power was required to pay qualifying cogeneration and small power production facilities under its Schedule 19 tariffs. App. 213a. The rider was not for an amount above avoided costs but was simply an attempt by the VSCC to determine elements of the utility's avoided costs that were not easily measured. The VSCC mentioned that such elements included the benefit from the reduction of use of fossil fuels, the deferral of major capacity additions by utilities, shorter construction lead times, and system reliability. The VSCC considered it its duty under PURPA to give reasonable weight to such intangible factors, "bearing in mind the mandate of PURPA that cogeneration and small power production is to be encouraged." Upon Virginia Power's motion for reconsideration of the order, the VSCC on December 6, 1985 (App. 229a), made it clear that "we did not hold,

that PURPA did not preempt North Carolina from making the disallowance. It held:

> "[A]voided costs" can be determined quite differently by different jurisdictions. Further, PURPA does not preempt this Commission's authority to review QF contracts in setting rates for the electric utilities operating in North Carolina. This Commission, in setting rates for NC Power in North Carolina, is not bound to interpret PURPA in the same manner as the Virginia SCC or to provide for the SCC's consideration of benefits unique to Virginia.

App. 68a.

The NCUC further ruled:

> The issue to be decided is whether the level of expense for the capacity associated with the [Ultra Cogen] projects is reasonable for ratemaking purposes in North Carolina. The Commission concludes that it is not.

App. 72a. The NCUC found that the capacity payments to Ultra Cogen were "out of line" with "other contemporaneous measures of avoided costs." App. 72a-73a.

The NCUC concluded:

> [I]t may be reasonable for Virginians to pay the extra costs associated with the [Ultra Cogen] projects. But it is unreasonable for North Carolinians to pay such extra costs, and our responsibility is to set fair and reasonable rates for North Carolina. We cannot accept the assumption implicit in the Com-

---

nor did we intend to suggest, that any QF is to be paid more than full avoided costs, for any reason." Further, the VSCC stated that its "holdings on rate levels were intended to match, not exceed, avoided costs." In order to clarify its November 15, 1985 order, and "consistent with [its] view that no QF should receive more that full avoided costs," the VSCC amended its November, 1985 order so as to include language that would "eliminate the potential for any QF to receive payments in excess of full avoided capacity costs." App. 232a.

> pany's position that our authority to set rates for North Carolina—and, by extension, the authority of the North Carolina Supreme Court—is circumscribed by the decision of an arbitrator in Virginia.[15]

App. 74a.

3. *The North Carolina Supreme Court's Decision.*

The North Carolina Supreme Court upheld the NCUC decision. It stated:

> The North Carolina Utilities Commission carefully reviewed the capacity rate set by the Virginia arbitrator's decision and found that he did not properly take into account other potential sources of power [those provided in the 1988 solicitation]. Thus, the Virginia arbitrator greatly overestimated NC Power's avoided costs. The North Carolina Utilities Commission's exclusion of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects is nothing more than the disallowance of the amount by which the contract rate exceeded NC Power's avoided costs. Therefore, there is no violation of PURPA.

App. 9a.

The North Carolina Supreme Court acknowledged that "the VSCC was required to apply the avoided-cost rule in determining wholesale rates pursuant to PURPA and FERC regulations." App. 5a. However, in response to the argument that the VSCC was doing just that and thus the NCUC had unlawfully interfered with the implementation of Federal law, the North Carolina court summarily concluded: "We disagree." App. 5a.

The North Carolina court acknowledged that *Nantahala* and *Mississippi Power* establish the preemptive effect of

---

[15] One Commissioner dissented: "I would hold that to disallow the recovery of costs actually incurred, we would need to find a lack of reasonable and prudent action on the part of North Carolina Power." App. 137a.

wholesale rates established pursuant to Federal authority. App. 6a. The court ruled, however, that because the VSCC had established a price above avoided costs, *Nantahala* and *Mississippi Power* did not apply. App. 6a.

Secondly, the North Carolina court ruled that the NCUC's disallowance did not violate the Commerce Clause. The court reasoned that the NCUC acted in a manner consistent with PURPA and the FERC regulations. App. 10a-11a. The court recognized that although "inconsistent determinations of avoided costs by the VSCC and the [NCUC] may burden NC Power, we believe this burden is a necessary consequence of doing business in more than one state." App. 11a. The court concluded that by not appealing the order of the VSCC, Virginia Power assumed the risk that the NCUC would not allow it to recover the "excess amount" from North Carolina ratepayers. App. 11a.

Two Justices dissented, arguing that the NCUC's actions were preempted by PURPA. The dissenters stated that the VSCC was acting pursuant to Federal law when it set rates for the Ultra Cogen purchases and that Virginia Power's obligation to pay the VSCC rate was a Federal obligation incurred pursuant to PURPA. The dissenters concluded that this Court's holdings in *Nantahala* and *Mississippi Power* controlled. Thus, the VSCC order was binding on the NCUC. App. 14a-21a.

REASONS FOR GRANTING THE PETITION

I. PURPA PREEMPTS NORTH CAROLINA'S APPLICATION OF ITS STATUTES.

A. This Case Raises Important Federal Issues.

In 1978, Congress enacted PURPA to prompt development of alternative energy sources to reduce the Nation's dependence upon oil and gas. PURPA encourages traditional electric utility companies to purchase power produced by alternative suppliers such as cogenerators to replace power generated by burning traditional fossil fuels. In turn, utilities sell their power to end-user customers at retail. Since the passage of PURPA, the Nation's electric utilities have entered into thousands of agreements with alternative suppliers and have purchased billions of dollars of electricity from these sources.

Like many of the Nation's large electric utilities, Virginia Power has drastically curtailed the construction of large fossil fuel and nuclear generating plants and has turned increasingly to alternative suppliers such as Ultra Cogen.[16] While Virginia Power has been in the forefront in responding to PURPA, it is by no means alone. Since 1990 most of the Nation's new capacity has been supplied by alternative suppliers, and more new sources of power have been constructed by qualifying facilities than by traditional utilities.[17]

---

[16] William W. Berry, *Competition in the Electric Industry: The Influence of PURPA, PUHCA, and Transmission Access*, ABA Section of National Resources Law Report (Fall, 1991).

[17] It has been estimated that non-utility generators (NUGs) accounted for more than 63% of all the on-line capacity added nationwide in 1992. In 1991 and 1992 together, of the 6500 mW of generating capacity created in the United States, 4100 mW were added by NUGs; only 700 mW of new generation were reported by investor-owned utilities such as Virginia Power, while 1700 mW were added by municipal and rural cooperative systems. Further, although in 1992 it was estimated that QFs in the United States already possessed the massive total cumulative capacity of more

Appropriate and fair implementation of PURPA is essential because so much of the Nation's electric production capacity is now being supplied through alternative suppliers. Appropriate and fair resolution of disputes over prices paid to alternative suppliers is essential because this is the crucial factor in insuring that PURPA's goals of fairness to the alternative supplier and the utilities' ratepayers are fulfilled.[18] The number of disputes related to QF/utility contracts and the financial consequences flowing from their resolution has increased dramatically in recent years and will continue to increase.[19]

---

than 82,000 mW, it was reported that QF filings in 1993 alone increased by more than 88% over 1992, to almost 12,000 mW. Jim Rossi, *Making Policy Through the Waiver of Regulations at the Federal Energy Regulatory Commission*, 47 Admin. L. Rev. 255, 257-58, 291 n.172 (1995).

[18] The most important obligation of the States in the implementation of PURPA has been the duty to set rates for purchases of electricity from cogenerators by electric companies. 18 C.F.R. § 292.304 (1994).

[19] Recent disputes involve analogous attempts to revisit the price utilities pay qualifying facilities pursuant to contracts approved in past years. In *Freehold Cogeneration Associates, L.P. v. Bd. of Regulatory Comm'rs of New Jersey*, 44 F.3d 1178 (3rd Cir. 1995), the Third Circuit held that the New Jersey regulators' implementation role under PURPA ended with its initial approval of the sales contract. The court stated: "there is specific federal statutory legislation, PURPA, that bars reconsideration of the prior approval of the [purchase power agreement] at least absent some basis in the law of contracts for setting aside the [purchase power agreement]." 44 F.3d at 1192.

FERC has also recently stated that the "appropriate time to challenge a state-imposed rate is up to or at the time the contract is signed, not several years into a contract which heretofore has been satisfactory to both parties." *Connecticut Light & Power*, 70 FERC ¶ 61,013, at pp. 61,029-30 (1995). *See also New York State Electric & Gas Co.*, 71 FERC ¶ 61,027 (1995) (denying after-the-fact petition to recover payments made in excess of avoided cost).

Similarly, in *Wilson v. Harlow*, 860 P.2d 793 (Okla. 1993), *cert. denied*, —— U.S. ——, 114 S.Ct. 1067, 127 L.Ed.2d 386 (1994), a utility customer brought a state common law breach of fiduciary

Through PURPA, Congress delegated to the States a number of administrative functions subject to FERC oversight. Congress required FERC to promulgate rules under which these administrative functions were to be carried out.[20] One important function Congress delegated to the States under FERC regulations was to settle disputes over the utilities' obligation to buy the alternative providers' power and disputes over the price of such power.[21]

Under the Federal Power Act and the Supremacy and Commerce Clauses of the United States Constitution, FERC decisions establishing obligations and prices of

---

duty claim against directors of a public utility for the directors' failure to rescind a contract between the utility and a cogenerator on the ground that the contract would unnecessarily cost the utility's ratepayers more than $2 billion. The contract had been approved by the Oklahoma Corporation Commission acting pursuant to PURPA. The Oklahoma Supreme Court found that such an action was preempted by PURPA:

> The Directors could not comply with federal mandates to honor long term, fixed rate contracts with cogenerators, while at the same time being required to rescind any such contract which, due to changed circumstances, became undesirable to ratepayers. Imposing such a fiduciary duty would thwart the objectives and purpose of Congress. PURPA was enacted to encourage electric utilities to purchase energy from cogenerators.

Wilson, 860 P.2d at 799. *See also Smith Cogeneration Management, Inc. v. Oklahoma Corp. Comm'n*, 863 P.2d 1227 (Okla. 1993) (finding state commission rule requiring QFs and electric utilities to include in their contracts a provision allowing the state commission to reconsider and modify the rates of such agreement to be preempted by PURPA because such a provision discourages cogeneration).

North Carolina's decision, while squarely in conflict with these decisions, goes considerably beyond the activities found preempted. Not only has North Carolina altered the impact of the qualifying facility-utility contract, it has refused to reduce the price the qualifying facility receives and has instead "trapped the costs," forcing Virginia Power to absorb them.

[20] 16 U.S.C. § 824a-3(a) (1988).

[21] 18 C.F.R. § 292.401 (1987).

wholesale power are binding on the States where the wholesale power is resold to end users. For PURPA to work, regulatory decisions made under PURPA establishing the obligation to purchase and the price of wholesale power must likewise be immune from collateral attack and disregard by the States in which the wholesale power is resold to the end user. As so much wholesale power now is provided by alternative suppliers covered by PURPA, and as many of the large utilities sell power in more than one State, decisions affecting wholesale power transactions under PURPA must receive the same protection as decisions affecting non-PURPA wholesale power transactions. The principles of Federal supremacy, which *Nantahala* and *Mississippi Power* made clear, will be severely undermined unless States are required to honor Federal decisions in implementing PURPA.

B. The Decision of the North Carolina Supreme Court Is in Conflict With This Court's Decisions.

In 1935 Congress recognized that there should be a single agency with exclusive jurisdiction over interstate transactions because such transactions affect more than one State, and regulation by each affected State would invite chaos.[22] Because all States would seek to advance "their respective local interests," the likely result would be inconsistent State determinations that would either prevent interstate wholesale producers from recovering all of their costs or unfairly shift costs among affected States.[23] Congress thus drew "a bright line easily ascertained" to

---

[22] *See* 16 U.S.C. § 824 (1988), Section 201 of the Federal Power Act (194a-195a). The primary purpose of Section 201 of the Federal Power Act was to give the Federal Power Commission authority that was denied the States—the authority to regulate the sale of electric energy at wholesale in interstate commerce. *Jersey Central Power & Light Co. v. Federal Power Comm'n*, 319 U.S. 61, 67-68 (1943).

[23] *Public Utilities Comm'n of Rhode Island v. Attleboro Steam & Electric Co.*, 273 U.S. 83, 89-90 (1927).

divide State and Federal regulatory authority.[24] Under this "bright line," States are prohibited from regulating those bulk power supply arrangements among utilities, regardless of the actual "impact of state regulation upon the national economy."[25]

In 1978 Congress enacted PURPA to encourage sales from alternative suppliers. Congress' intent was to promote power production that reduced reliance on fossil fuels.[26] But PURPA's encouraged transactions are wholesale, interstate transactions that only the FERC was authorized to oversee. In order to assuage concerns that passage of PURPA would unduly restrict State retail rate decision-making, Congress delegated to the States authority to resolve disputes between alternative providers and the electric utilities.[27] Congress directed FERC to promulgate mandatory regulations under which the States were to exercise this Federal authority.[28]

Importantly, PURPA carved out an exception to FERC's exclusive jurisdiction over wholesale interstate power transactions. Equally important, the authority the States exercise in administering PURPA is Federal, not State. Also, by its delegation to States of Federal authority to oversee wholesale transactions, Congress did nothing to minimize the importance of a unified, national

---

[24] *Federal Power Comm'n v. Southern California Edison Co.*, 376 U.S. 205, 215-16 (1964).

[25] *Id.*

[26] *Federal Energy Regulatory Comm'n v. Mississippi*, 456 U.S. 743, 745-46 (1982).

[27] 124 Cong. Rec. H35002 (daily ed. October 10, 1978) ("The conference substitute does not change the primary responsibility of the States with respect to [retail] electric utility rates, but it places Federal responsibilities and obligations on the State commissions in the exercise of their responsibilities and on utilities within the States which are not otherwise regulated by State Commissions.").

[28] 16 U.S.C. § 824a-3(a) (1988).

policy concerning wholesale interstate power transactions. The dangers from regulation by each State of disputes over wholesale transactions are the same whether the transaction is covered by the original provisions of the Federal Power Act or PURPA.

When Virginia required Virginia Power to purchase power from Ultra Cogen and pay Ultra Cogen $341 per kW, Virginia was making a Federal decision, not a State one. The Virginia decision fixed an obligation and a rate affecting wholesale interstate power. The power Virginia Power purchases from Ultra Cogen is intermixed with Virginia Power's other sources of wholesale power and power from its own generation resources. Virginia Power draws upon these intermixed sources of power to fulfill its commitment to users in North Carolina and Virginia.

By contrast, when North Carolina disallowed recovery of $1.39 million per year of the price Virginia Power pays Ultra Cogen, North Carolina was exercising State authority, not its Federal authority delegated to it under PURPA from Congress. North Carolina was engaged in traditional retail ratemaking under authority granted to it by the State legislature.

In *Nantahala Power and Light Co. v. Thornburg*,[29] this Court addressed whether a State in establishing retail electric rates to be paid by its citizens was bound by FERC's determinations establishing wholesale power allocations and costs. FERC had examined wholesale power agreements determining how much low cost entitlements power Nantahala should receive. This determination greatly affected Nantahala's wholesale power costs. The North Carolina Utilities Commission, in establishing Nantahala's retail rates, determined that Nantahala received too few entitlements under a FERC approved allocation and refused the utility recovery of a large percentage of its wholesale power costs.

---

[29] 476 U.S. 953 (1986).

This Court reversed the North Carolina Supreme Court's affirmance of the NCUC. This Court found North Carolina's actions preempted under the Supremacy Clause and determined that once FERC sets a wholesale rate, a State may not conclude that the FERC-approved wholesale rate is unreasonable. The Court held:

> "[T]here can be no divided authority over interstate commerce, and . . . the acts of Congress on that subject are supreme and exclusive." Consequently, state efforts to regulate commerce must fall when they conflict with or interfere with Federal authority over the same activity.[30]

The Court also held that in establishing retail rates:

> A State must . . . give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that States do not interfere with this authority.
>
> * * *
>
> "Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States."
>
> * * *
>
> When FERC sets a rate between a seller of power and a wholesaler-as-buyer, a State may not exercise its undoubted jurisdiction over retail rates to prevent the wholesaler-as-seller from recovering the costs of paying the FERC-approved rate. . . . Such a "trapping" of costs is prohibited. Here, Nantahala cannot fully recover its costs of purchasing at the FERC-approved rate if NCUC's order is allowed to stand.[31]

---

[30] 476 U.S. at 964 (citations omitted).

[31] 476 U.S. at 966, 970 (citations omitted).

In this case North Carolina's actions have again "trapped" Federally determined wholesale costs, just as in *Nantahala*. As in *Nantahala*, North Carolina is exercising its jurisdiction over retail rates to prevent a wholesaler-as-seller from recovering costs of paying a Federally-established rate. The only distinction between *Nantahala* and the facts presented by this case is that Virginia, acting on authority delegated to it by Congress through PURPA under mandatory FERC guidelines, rendered the Federal decision instead of FERC acting pursuant to the Federal Power Act.[32]

Any argument that this distinction renders *Nantahala* inapplicable is unavailing. This Court has determined that § 210 of PURPA [33] constitutionally requires States to implement the Federal Act in the manner Virginia has here. In *Federal Energy Regulatory Comm'n v. Mississippi* [34], Mississippi challenged PURPA's Title I and III and § 210 as being beyond the scope of the Commerce Clause and an invasion of State sovereignty in violation of the Tenth Amendment. In rejecting the Commerce Clause argument this Court held:

---

[32] The decision of the VSCC was also impliedly affirmed by FERC. In *Doswell Limited Partnership*, 50 FERC ¶ 61,251 at p. 61,758 (1990) (App. 140a), the FERC specifically referenced the order of the VSCC adopting the findings of the arbitrator in the Ultra Cogen proceeding in holding that the proposed rates of the applicant in the FERC proceeding, Doswell Limited Partnership, did not exceed Virginia Power's avoided cost under PURPA. Citing the VSCC's order, the FERC concluded: "That Chesterfield 7 was an accurate representation of Virginia Power's avoided cost is corroborated by the Virginia Commission's adoption of Chesterfield 7's costs to set avoided costs rates for certain of contracts in the same time frame involved here." *Id.* This statement makes the case remarkably similar to *Nantahala*, particularly in that it demonstrates that the VSCC's actions were appropriate avoided costs determinations under Federal law.

[33] 16 U.S.C. § 824a-3 (1988).

[34] 456 U.S. 742 (1982).

> [I]t is difficult to conceive of a more basic element of interstate commerce than electric energy, a product used in virtually every home and every commercial or manufacturing facility. No state relies solely on its own resources in this respect. . . . Indeed, the utilities involved in this very case . . . sell their retail customers power that is generated in part beyond Mississippi's borders. . . . The intrastate activities of these utilities, although regulated by the Mississippi Public Service Commission, bring them within the reach of Congress' power over interstate commerce.
>
> * * *
>
> It is not for us to say whether the means chosen by Congress represent the wisest choice. It is sufficient that Congress was not irrational in concluding that limited federal regulation of retail sales of electricity and natural gas, and of relationships between cogenerators and electric utilities, was essential to protect interstate commerce.[35]

With respect to the Tenth Amendment challenge, this Court ruled:

> Clearly, Congress can pre-empt the States completely in the regulation of retail sales by electricity and gas utilities and in the regulation of transactions between such utilities and cogenerators.[36]

This Court specifically addressed the kind of action performed by the VSCC in this case, an arbitration and order setting wholesale rates:

> The statute's substantive provisions require electricity utilities to purchase electricity from, and to sell it to, qualifying cogenerator and small power production facilities. . . Yet FERC has declared that state commissions may implement this by, among other things, "an undertaking to resolve disputes between qualify-

---

[35] 456 U.S. at 757-58 (citations omitted).

[36] 456 U.S. at 759.

> ing facilities and electric utilities arising under [PURPA]." [37]

Regarding the State's duty to resolve disputes, this Court further held that:

> [S]tate courts have a unique role in enforcing the body of federal law. . . . Thus the state courts were directed to heed the constitutional command that "the policy of the federal Act is the prevailing policy in every state . . . and should be respected in the courts of the State."
>
> So it is here. The Mississippi Commission has jurisdiction to entertain claims analogous to those granted by PURPA, and it can satisfy § 210's requirements simply by opening its doors to claimants. That the Commission has administrative as well as judicial duties is of no significance. Any other conclusion would allow the States to disregard both the preeminent position held by federal law throughout the Nation, . . . and the congressional determination that the federal rights granted by PURPA can appropriately be enforced through state adjudicatory machinery. Such an approach, *Testa* emphasized, "flies in the face of the fact that the States of the Union constitute a nation," and "disregards the purpose and effect of Article VI of the Constitution." [38]

Based on this precedent, Virginia had full authority to render the Federal decision, and, having done so, North Carolina was bound to adhere to it just as though FERC itself had acted.

North Carolina's path in circumventing the preemptive reach of the Federal decision rendered by the Virginia Commission is equally unavailing. The North Carolina Supreme Court states that Virginia's establishment of costs is not binding on North Carolina to the extent Virginia establishes capacity costs above $171 per kW because any

---

[37] 456 U.S. at 759-60 (citations omitted).

[38] 456 U.S. at 760-61 (citations omitted).

authorization above $171 exceeds "avoided costs." App. 6a. The North Carolina court suggests that any requirement that Virginia Power pay a price above $171 per kW is action that contravenes PURPA because PURPA prohibits prices above avoided costs. App. 8a-9a. The North Carolina court implies that such an "in excess of avoided cost" determination is based on State, not Federal, authority. App. 4a-5a.

North Carolina's analysis of the Virginia decision establishing the utility's obligation to buy power from the qualifying facility and the price to be paid for the power raises an important Federal preemption issue. In its orders, the Virginia Commission unequivocally stated that it was establishing price as the avoided cost of the utility as required by PURPA and in accordance with mandatory FERC guidelines. App. 171a-172a.

The Virginia Commission faced conflicting recommendations as to price. The qualifying facility owner argued for a price based on an administratively determined avoided cost; the utility sought to base the price on avoided costs determined in a competitive bid process. In resolving the dispute, the Virginia Commission applied FERC regulations. App. 172a. The Virginia Commission interpreted the regulations to require that avoided costs be established on the date the utility's obligation to buy the power was established, held to be the date the qualifying facility filed its petition to arbitrate. The Virginia Commission also found that an administratively determined avoided cost was the proper method for computing the price to be paid Ultra Cogen. App. 172a-173a, 178a. The Virginia Commission expressly followed PURPA in making a Federal decision. North Carolina is attempting to escape its obligation to honor the Federal decision by recasting the Virginia decision from a Federal mandate into a State action against the issuing State's wishes.

Both the NCUC and the North Carolina Supreme Court are tellingly silent on the interpretation of the FERC reg-

ulation that establishes the date on which avoided costs must be determined.[39] North Carolina cannot ignore FERC's requirement of determining the timing of the avoided costs. Virginia ruled that the determination had to be made on November 12, 1987. App. 172a-173a. On that date, bids from the subsequent 1988 solicitation were not known and therefore could not be used. North Carolina simply pretends that the timing regulation does not exist. This omission reveals that North Carolina's labeling of the Virginia decision as an "in excess of" avoided cost decision is completely invalid under Federal law.

The North Carolina decision deals a serious blow to PURPA. PURPA simply will not work if one State, exercising Federal authority, establishes a price an electric utility must pay a cogenerator, and a second State, exercising State retail ratemaking authority, denies the utility recovery of or "traps" a portion of the costs. Utilities, such as Virginia Power, to whom PURPA's provisions are directed, most certainly will be discouraged from buying power from alternative suppliers when one State can require them to buy power at a mandated price and then another State can refuse to permit reimbursement of the mandated price through recovery in retail rates. If the North Carolina decisions are allowed to stand, a multistate utility would be forced to obtain approvals of avoided cost rates to be paid to a qualifying facility in each of the States in which it serves. These redundant approvals certainly would lead to significant delays in the execution of a contract between the utility and qualifying facilities and would significantly discourage the development of those facilities to the detriment of the goals of PURPA.

Although Virginia Power has accepted its responsibilities under PURPA, the North Carolina Utilities Commission lightly dismissed the agency's obligations. "In making this decision, we recognize our obligation to encour-

---

[39] 18 C.F.R. § 292.304(d)(2) (1994).

age QFs, but that is not the issue here. The issue here is ascertaining reasonable operating expenses for purposes of setting just and reasonable rates in North Carolina." App. 74a. Such lip service to PURPA, while requiring the utility to absorb $1.39 million annually of the payment made to the qualified facility in order to protect North Carolina ratepayers, is prodigal stewardship of North Carolina's responsibilities under PURPA that should be reviewed by this Court.

II. NORTH CAROLINA'S RULINGS VIOLATE THE COMMERCE CLAUSE.

Despite the substantial burden placed on interstate wholesale power transactions, the North Carolina court held that the trapping of costs by inconsistent decisions under PURPA does not violate the Commerce Clause. Clearly, however, state action can violate the Commerce Clause by directly regulating or discriminating against interstate commerce.[40] This Court has held that a State action directly burdens interstate commerce when it adversely affects commerce by subjecting activities to inconsistent regulations.[41] Similarly, this Court has held that no State may force an out-of-state seller to seek regulatory approval in one State before undertaking a transaction in another State.[42] The North Carolina decision ignores such holdings. Instead, North Carolina's decision plainly was intended to shield North Carolina

---

[40] *Edgar v. MITE Corp.*, 457 U.S. 624, 643 (1982). *See also New England Power Co. v. New Hampshire*, 455 U.S. 331, 340-41 (1982) (holding that section of Federal Power Act was not an affirmative grant of power to the states to burden interstate commerce in a manner that would otherwise not be permissible, and stating that nothing in the Act evinced an intent to alter limits on state power otherwise imposed by the Commerce Clause).

[41] *CTS Corp. v. Dynamics Corp. of America*, 481 U.S. 69, 87-88 (1987).

[42] *Healy v. Beer Institute, Inc.*, 491 U.S. 324 (1989).

electric customers from costs imposed pursuant to Federal law, regardless of the effects on Virginia customers. Such effects include the subsidization of North Carolina ratepayers. The actions of North Carolina are precisely the kind of economic protectionism that is per se unconstitutional under the Commerce Clause.[43]

In this case the North Carolina court admitted that there were "inconsistent determinations of avoided costs by the VSCC and the [NCUC that] may burden NC Power." App. 11a. The court did not suggest that such burden was merely incidental, but concluded that such "burden is a necessary consequence of doing business in more than one state." App. 11a. Further, the North Carolina court held that there was no Commerce Clause violation because, by not appealing the VSCC order to the Virginia courts, Virginia Power "accepted the risk" that its Federally-imposed costs would be denied by the North Carolina commission. App. 11a.

The holding of North Carolina not only ignores the decisions of this Court, it conflicts with the decision of the Federal Eighth Circuit in *Middle South Energy, Inc. v. Arkansas Public Service Comm'n.*[44] In *Middle South* the Eighth Circuit held that a State utility commission's attempt to prohibit a utility's wholesale purchases of higher-cost power from an adjacent state created an unlawful preference under the Commerce Clause for citizens in the regulating jurisdiction. Here, in contrast, the North Carolina court achieved the same result attempted by the Arkansas commission by denying Virginia Power's recovery of costs of power purchased in an adjacent state. As the *Middle South* court recognized, this is plainly an unlawful preference for North Carolina customers over Virginia customers.

---

[43] *Philadelphia v. New Jersey*, 437 U.S. 617, 621-28 (1978).

[44] 772 F.2d 404 (8th Cir. 1985), *cert. denied*, 474 U.S. 1102 (1986).

The decision of the North Carolina court that inconsistent regulatory decisions in the context of wholesale electric power transactions that effect a preference for North Carolina customers does not violate the Commerce Clause raises a substantial Federal question that should be reviewed by this Court.

CONCLUSION

The Court should grant Virginia Power's petition and set the case for full briefing and argument on the merits. The Federal issues are too substantial, and have too large an impact on the implementation of PURPA, for the North Carolina courts and regulators to be the only tribunals to consider them.

Respectfully submitted,

EDWARD S. FINLEY, JR.*
JAMES L. HUNT
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

(2) Sup. Ct. U.S.

94-1868 MAY 15 1995

No. ——

OFFICE OF THE CLERK

IN THE

Supreme Court of the United States

OCTOBER TERM, 1994

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

EDWARD S. FINLEY, JR.*
JAMES L. HUNT
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

WILSON - EPES PRINTING CO., INC. - 789-0096 - WASHINGTON, D.C. 20001

236 pp

TABLE OF CONTENTS

APPENDIX A — Page

Opinion of the Supreme Court of North Carolina, (December 9, 1994) 1a

APPENDIX B

Order of the Supreme Court of North Carolina (February 15, 1995) 22a

APPENDIX C

Order of the North Carolina Utilities Commission (February 26, 1993) 24a

APPENDIX D

Order of the Federal Energy Regulatory Commission (February 28, 1990) 140a

APPENDIX E

Order of the Virginia State Corporation Commission (February 26, 1988) 164a

APPENDIX F

Decision on Pricing Issue, Thomas P. Harwood, Jr., Virginia State Corporation Commission (April 27, 1988) 169a

APPENDIX G

Interim Order of the Virginia State Corporation Commission (May 27, 1988) 175a

APPENDIX H

Award and Final Order of the Virginia State Corporation Commission (September 30, 1988) 184a

TABLE OF CONTENTS—Continued

APPENDIX I — Page

Order of the Virginia State Corporation Commission Ending Proceedings (November 18, 1988) 191a

APPENDIX J

Excerpts from the Federal Power Act, 16 U.S.C. §§ 824, 824a-3 ..... 194a

APPENDIX K

Excerpts from Regulations under the Public Utility Regulatory Policies Act of 1978, 18 CFR Part 292 (1987) 198a

APPENDIX L

Order of the Virginia State Corporation Commission (January 11, 1983) 203a

APPENDIX M

Final Order and Order Denying Petition for Reconsideration of the Virginia State Corporation Commission (November 15, 1985; December 6, 1985) 213a

APPENDIX N

Rule 29.1 Statement 233a

APPENDIX A

Opinion of the Supreme Court of North Carolina, (December 9, 1994)

IN THE SUPREME COURT
OF NORTH CAROLINA

No. 230A93

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION

v.

NORTH CAROLINA POWER

(Filed 9 December 1994)

Justice MITCHELL dissenting in part.

Justice WEBB joins in this dissenting opinion.

FRYE, Justice.

This is an appeal from an order of the North Carolina Utilities Commission (Commission) in a general rate case involving Virginia Electric and Power Company (VEPCO) which operates as North Carolina Power (NC Power) in North Carolina and Virginia Power in Virginia. NC Power is a public utility operating under the laws of North Carolina and is engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation.

Procedurally this case comes to this Court as follows:

On 31 July 1992, NC Power filed an application with the Commission to adjust and increase its rates and charges for electric service to its North Carolina retail customers effective 30 August 1992. The Commission ordered that $1.39 million of the capacity costs paid by NC Power to Ultra Cogen Systems (Ultra Cogen),[1] a cogenerator, be disallowed in calculating approved North Carolina retail rates. Cogeneration involves the simultaneous production of both thermal energy, such as heat or steam, and electric power, usually at an industrial site. By making productive use of the excess heat produced in the generation of thermal energy, cogeneration can produce electricity at a reduced cost. Pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), regulations of the Federal Energy Regulatory Commission (FERC) promulgated thereunder, and implementation mechanisms of the states, electric utilities are required to purchase power produced by qualifying cogeneration and small power production facilities and are required to pay their "avoided costs" for the power unless another rate is negotiated.

In the spring and summer of 1986, NC Power was inundated with offers from cogenerators, that were Qualifying Facilities pursuant to federal law, to sell it electricity. In response, in December 1986, NC Power instituted a solicitation process and sent letters to potential sellers. One of NC Power's letters was sent to Ultra Cogen.

On 30 January 1987, in response to this solicitation, NC Power received proposals from Ultra Cogen to sell power from nine projects. Based on numerous factors, including cost, NC Power informed Ultra Cogen in March

---

[1] Ultra Cogen Systems has been succeeded in interest by Hadson Power and later by LG&E Development. It will be referred to as Ultra Cogen in this opinion.

1987 that it was rejecting the offer. Between 12 November 1987 and 3 December 1987, Ultra Cogen initiated arbitration proceedings with the Virginia State Corporation Commission (VSCC) seeking to arbitrate NC Power's rejection of its offer. Ultra Cogen requested the VSCC to order NC Power to enter into power purchase agreements. NC Power requested dismissal of the petitions on the ground that the VSCC had expressed its general approval of competitive bidding in a final order issued 29 January 1988. On 26 February 1988, the VSCC rejected NC Power's motion to dismiss and designated Commissioner Thomas Harwood, Jr., of the VSCC as final arbitrator of the dispute. On 30 September 1988, Commissioner Harwood ordered NC Power to execute agreements with Ultra Cogen. This order was adopted by the entire VSCC on 18 November 1988. In compliance with the VSCC's orders, NC Power executed contracts with Ultra Cogen. Additional facts will be discussed where pertinent to the issues raised by NC Power.

The questions presented on this appeal are: (1) whether the Commission's disallowance of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects violates PURPA, N.C.G.S. § 62-133, or the Commerce Clause of the United States Constitution; and (2) whether the Commission's exclusion of $28,000 in officers' salaries violates N.C.G.S. § 62-133. We answer both questions in the negative and affirm the Commission's order.

I.

As stated previously, section 210 of PURPA requires electric utilities to purchase power from qualifying cogeneration and small power production facilties. PURPA directs the Federal Energy Regulatory Commission (FERC) to prescribe rules to encourage cogeneration. These rules must insure that rates for such purchases shall be just and

reasonable to electric consumers and in the public interest, and shall not discriminate against qualifying cogenerators. 16 U.S.C. § 824a-3(b) (1985). PURPA further requires that no rule prescribed for this purpose shall provide a rate which exceeds the incremental cost to the electric utility of alternative electric energy. *Id.* The "incremental cost of alternative electric energy" means the cost to the electric utility to produce or purchase the electric energy which, but for the purchase from such cogenerator or small power producer, the utility would generate or purchase from another source. *Id.* at § 824a-3(d). PURPA also provides that each state regulatory authority shall implement the FERC rule concerning purchases from cogenerators for each electric utility for which it has ratemaking authority. *Id.* at § 824a-3(f).

FERC regulations concerning the arrangements between electric utilities and cogenerators parallel the statutory provisions by requiring that rates for purchases shall be just and reasonable to consumers and in the public interest, and shall not discriminate against cogenerators. 18 C.F.R. § 292.304(a)(1) (1994). The regulations specifically provide that no utility is required to pay more than the avoided costs for purchases. *Id.* at § 292.304(a)(2). "Avoided costs" means the incremental costs which the utility would incur if it supplied the power itself or purchased it from another souurce. *Id.* at § 292.101(b)(6). The regulations further provide that they do not limit the ability of parties to negotiate agreements for rates and terms different from those called for in the regulations. *Id.* at § 292.301(b)(1). For example, a rate for cogeneration purchases may be less than the avoided costs if the state regulatory authority determines that a lower rate is consistent with the regulations and is sufficient to encourage cogeneration and small power production. *Id.* at § 292.304(b)(3). However, in April 1988, FERC held that it is impermissible for states to impose rates exceeding the avoided costs on wholesale purchases

in interstate commerce. *Re Orange and Rockland Utilities, Inc.*, 92 P.U.R.4th 1, 14-15 (1988).[2]

The United States Supreme Court has interpreted PURPA and the FERC regulations to mean that a state regulatory authority, in implementing PURPA and the federal regulations, must apply the avoided-cost rule in the absence of a waiver granted by FERC or a specific contractual agreement setting a price that is lower than the avoided cost. *American Paper Inst. v. American Elec. Power*, 461 U.S. 402, 76 L. Ed. 2d 22 (1983). Therefore, in this case, the VSCC was required to apply the avoided-cost rule in determining wholesale rates pursuant to PURPA and FERC regulations. While both parties in this case are in agreement that the avoided-cost rule is the appropriate method for determining wholesale rates pursuant to PURPA and FERC regulations, they disagree as to what these avoided costs should have been. NC Power contends that when the VSCC set the price it had to pay Ultra Cogen for the wholesale power, the VSCC was implementing federal law and making a determination affecting wholesale power in interstate commerce. Furthermore, when the North Carolina Utilities Commission, in setting North Carolina retail rates, refused to allow NC Power to recover the $1.39 million that the VSCC required NC Power to pay Ultra Cogen, it unlawfully interfered with the VSCC's implementation of federal law. We disagree.

---

[2] *Orange and Rockland Utilities* reversed the FERC's earlier position in the preamble to section 210 of PURPA. In the preamble, FERC stated in pertinent part:

> If a State program were to provide that electric utilities must purchase power from [qualifying facilities] at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on [FERC's] rules.

45 Fed. Reg. 12,214, 12,221 (1980).

NC Power relies on *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 90 L. Ed. 2d 943 (1986), and *Mississippi Power & Light Co. v. Mississippi ex rel. Moore,* 487 U.S. 354, 101 L. Ed. 2d 322 (1988), in support of its arguments that North Carolina is preempted by Virginia's decision. Those cases address the preemptive effect of a rate or apportionment set by FERC for a wholesale transaction subject to regulation under the Federal Power Act. Under FERC regulations, the purchase price for power sold by cogenerators is exempt from regulation by FERC under the relevant provisions of the Federal Power Act, 18 C.F.R. § 292.601(c), and the rate is determined under federal rules implemented by each state for utilities subject to their ratemaking authority. 18 C.F.R. §§ 292.304, 292.401(a). However, states cannot impose purchase rates in excess of avoided costs. *Re Orange and Rockland Utilities, Inc.,* 92 P.U.R.4th 1, 14-15. Therefore, we conclude that the Commission's disallowance of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects does not violate PURPA to the extent it only excludes the amount *above* avoided costs.

We must now compare the VSCC's determination of avoided costs with the Commission's determination of avoided costs.

A. The VSCC's Measure of Avoided Costs

On 27 April 1988, Commissioner Harwood ruled that Ultra Cogen was entitled to receive avoided costs payments determined as of 12 November 1987, the date Ultra Cogen began to file arbitration petitions with the VSCC. The Virginia arbitrator further concluded that the avoided cost payments should be based on NC Power's costs of constructing and operating a gas-fired facility called Chesterfield Unit No. 7, which is intended to be the prototype for any new facility built through the mid-1990's.

In an interim order of 27 May 1988, Commissioner Harwood specified various "key terms and conditions that should be included in a power purchase agreement between the parties." These terms and conditions included the determination that the capacity price for each of the Ultra Cogen projects at issue shall be $341.23 per dependable kilowatt for the first fifteen years of operation and $189.70 for years sixteen through twenty-five. In a final order dated 30 September 1988, he ordered NC Power to execute agreements with Ultra Cogen including these terms. This order was adopted by the entire VSCC on 18 November 1988. In compliance with the VSCC's orders, NC Power executed contracts with Ultra Cogen. NC Power did not exercise its right to appeal the VSCC's order and it did not file the contracts with the North Carolina Utilities Commission. During the test year in this case, NC Power paid Ultra Cogen $2.8 million on a North Carolina retail allocation basis for capacity payments under these contracts.

B. The Commission's Measure of Avoided Costs

On 26 February 1993 the Commission entered an order granting a partial rate increase finding that it was not bound by the actions of the VSCC with regard to the Ultra Cogen contracts and concluding that it was appropriate to reduce operation and maintenance expenses by $1.39 million to reflect the removal of unreasonable capacity costs.

The Commission compared the Ultra Cogen contracts to the results of the 1986 and 1988 competitive bidding solicitations and determined that the rates in the Ultra Cogen contracts exceeded NC Power's avoided costs at the time the arbitration petitions were filed. The 1986 solicitation, which used NC Power's proposed Chesterfield No. 7 as a benchmark, produced average capacity costs of $141 per dependable kilowatt compared to $341 per dependable kilowatt for the Ultra Cogen projects. The

evidence showed that the 1986 projects were expected to operate at a 32.2 percent capacity factor compared to 27.1 percent for the Ultra Cogen projects, thus eliminating any justification for the higher capacity costs on the basis of lower energy costs.

The Commission noted that the Virginia arbitrator himself stated in a February 1990 order that payments for the Doswell projects (from the 1986 solicitation) were based on the avoided costs of Chesterfield No. 7 and were reasonable. The Doswell projects and the Ultra Cogen projects came on-line within a few months of one another (Doswell on 3 May and 10 May 1992 and Ultra Cogen on 22 February, 7 March, and 1 July 1992). The capacity cost for the Doswell projects is $146 per dependable kilowatt, while the capacity cost for the Ultra Cogen projects is $341 per dependable kilowatt. Furthermore, the Ultra Cogen projects' average capacity factor, based on economic dispatch, is approximately one-half that of the Doswell projects' average capacity factor, which indicates the Ultra Cogen projects' energy costs are greater.

The seven projects that were selected in the 1988 solicitation and were operational at the time of the hearing, have an average capacity cost of $171 per dependable kilowatt and a combined capacity factor of 35.9 percent. The Commission used the average capacity costs from the 1988 solicitation as a proxy for what the 1986 solicitation results would have been if the 1986 solicitation had occurred at the time the Ultra Cogen contracts were signed. Using the results of the later solicitation did not prejudice NC Power, but rather allowed it to include $30 per dependable kilowatt (or $240,000) more in rates than if the 1986 results were used.

We conclude that it was not unreasonable for the North Carolina Utilities Commission to use the competitive bidding measure in determining avoided costs, thereby rejecting the measure used by the VSCC. In fact, NC Power argued before the VSCC that competitive bidding should

be the measure used. The North Carolina Utilities Commission carefully reviewed the capacity rate set by the Virginia arbitrator's decision and found that he did not properly take into account other potential sources of power. Thus, the Virginia arbitrator greatly overestimated NC Power's avoided costs. The North Carolina Utilities Commission's exclusion of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects is nothing more than the disallowance of the amount by which the contract rate exceeded NC Power's avoided costs. Therefore, there is no violation of PURPA.

Next, we address the question of whether the Commission's disallowance of $1.39 million in expenses for capacity payments violates N.C.G.S. § 62-133. Section 62-133(b)(3) provides that the Commission shall determine a utility's "reasonable operating expenses" when setting rates. NC Power contends that the Commission, contrary to North Carolina law, arbitrarily decided that the rates paid Ultra Cogen were too high. NC Power also argues that the Commission, in deciding the reasonableness of operating expenses, must determine whether management has acted prudently. We disagree.

This Court rejected this argument in *State ex rel. Utilities Comm'n v. Carolina Power & Light Co.*, 320 N.C. 1, 358 S.E.2d 35 (1987), reasoning that:

> [A]lthough management prudence may be an important factor considered by the Commission in a general rate case, management prudence *vel non* does not control the Commission's decision as to whether to adjust test period data to reflect abnormalities having a probable impact on the utility's revenues and expenses during the test period, in order that it may set reasonable rates in compliance with N.C.G.S. § 62-133.

Id. at 12, 358 S.E.2d at 41. The conclusion that management imprudence is only one method of demonstrating

that a given expense is unreasonable is also consistent with the standard applied in *State ex rel. Utilities Comm'n v. Intervenor Residents,* 305 N.C. 62, 286 S.E.2d 770 (1982). In *Intervenor Residents,* we held that the Commission must always determine that expenses paid to affiliated companies are reasonable. "If there is an absence of data and information from which either the propriety of incurring the expense or the reasonableness of the cost can readily be determined, the Commission may require the utility to prove [its] propriety and reasonableness by affirmative evidence." *Id.* at 75, 286 S.E.2d at 778.

The findings of the Commission, when supported by competent evidence, are conclusive. *State ex rel. Utilities Comm'n v. Thornburg,* 325 N.C. 484, 385 S.E.2d 463 (1989). In this case, the Commission reviewed the capacity rate set by the Virginia arbitrator and determined that he did not properly take into account other potential sources of power. Thus, his assessment of avoided costs was unreasonably high. The Commission's exclusion of $1.39 million in expenses for capacity payments was merely the disallowance of the amount by which the contract rate exceeded NC Power's avoided costs. Therefore, we conclude that the Commission properly disallowed expenses for unreasonably high payments to Ultra Cogen in accordance with N.C.G.S. § 62-133.

Another issue raised by NC Power is whether the Commission's disallowance of these expenses violates the Commerce Clause of the United States Constitution. Under Article I, Section 8 of the U.S. Constitution, Congress shall have the power "[t]o regulate Commerce . . . among the several States . . . ." In *FERC v. Mississippi,* 456 U.S. 742, 72 L. Ed. 2d 532, *reh'g denied,* 458 U.S. 1131, 73 L. Ed. 2d 1401 (1982), the Court determined that Congress has the power under the Commerce Clause to regulate the relationships between cogenerators and electric utilities in order to protect interstate commerce. Under PURPA, federal law specifically requires each

state to implement federal guidelines for each utility whose rates it regulates. 16 U.S.C. § 824a-3(f). Thus, the Commission is authorized by Congress to act with regard to arrangements between cogenerators and NC Power. The Commission's disallowance of the amount by which the Ultra Cogen contracts exceeded NC Power's avoided costs is consistent with PURPA and the FERC's regulations and constitutes lawful retail ratemaking. The Commission's actions here do not violate the Commerce Clause.

While we recognize that inconsistent determinations of avoided costs by the VSCC and the Commission may burden NC Power, we believe this burden is a necessary consequence of doing business in more than one state. Here, NC Power believed that the capacity rate set by the Virginia arbitrator and ultimately adopted by the VSCC was higher than required by federal law. In fact, NC Power argued before the VSCC that the competitive bidding method should have been used in determining avoided costs. However, instead of appealing the adverse decision of the VSCC to the Virginia courts, NC Power accepted the VSCC decision which required it to pay a rate in excess of avoided costs. NC Power thus accepted the risk that the North Carolina Utilities Commission might not permit it to recover the excess amount from its North Carolina consumers.

II.

Finally, we address the question of whether the Commission's exclusion of $28,000 in officers' salaries violates N.C.G.S. § 62-133. NC Power argues that absent a showing that such salaries are unreasonable or will not actually be incurred, there was no basis for the exclusion of these expenses. We disagree.

One of the critical elements of the ratemaking process is a determination of what expenses are appropriate for inclusion in rates. *State ex rel. Utilities Comm'n v. Eddle-*

man, 320 N.C. 344, 358 S.E.2d 339 (1987), and *State ex rel. Utilities Comm'n v. Public Staff*, 317 N.C. 26, 343 S.E.2d 898 (1986). The Commission argues that it is the policy of the Commission to make executive salary adjustments. *See In re Application of Duke Power Co.*, 75 NCUC Report 298 (1985). In *Application of Duke Power Co.*, the Commission concluded that Duke Power's shareholders shoud bear fifty percent of the overall compensation of those officers whose functions are more closely linked with meeting the demands of the common shareholders. *Id.* The Commission has reached the same conclusion in subsequent rate cases. *See, e.g., In re Application of Duke Power Co.*, 76 NCUC Report 279 (1986), and *In re Application of Carolina Power & Light Co.*, 77 NCUC Report 272 (1987).

In the present case, the Public Staff proposed to remove fifty percent of the salaries of NC Power's President/Chief Executive Officer, the Chairman of the Board of Directors, and the President/Chief Executive Officer of NC Power's sole common stockholder, Dominion Resources, Inc. The Commission concluded that the Public Staff adjustment to exclude fifty percent of the compensation of the three officers in question was appropriate, explaining its reasons for making the executive salary adjustments:

> Witness Maness testified that these three individuals are closely linked to meeting the demands of the Company's common shareholders. All three serve on the VEPCO Board of Directors, as well as the Dominion Resources, Inc. Board of Directors. The Chairman of the VEPCO Board is also the Chairman of the Dominion Resources, Inc. Board, as well as the boards of Dominion Resources, Inc.'s other subsidiaries, Dominion Capital, Dominion Energy, and Dominion Lands. Witness Maness testified that this adjustment is especially appropriate for VEPCO given the nature of Dominion Resources, Inc.'s non-

> regulated business interests. Witness Maness stated that the interests of Dominion Resources, Inc. as they relate to its non-regulated businesses may not always coincide with the interests of VEPCO's retail ratepayers. Witness Maness also testified that the Commission has adopted an adjustment consistent with his approach in each of the seven Duke, CP&L, and VEPCO general rate cases decided since November 1984.

This Court will not disturb the Commission's findings of fact which are supported by competent, material, and substantial evidence in view of the whole record and are not arbitrary or capricious. *State ex rel. Utilities Comm'n v. Thornburg,* 325 N.C. 484, 385 S.E.2d 463 (1989). The authority to regulate the rates of public utilities lies with the Commission and a reviewing court may not modify or reverse its determination merely because the court would have reached a different finding based on the evidence. *State ex rel. Utilities Comm'n v. Eddleman,* 320 N.C. 344, 358 S.E.2d 339 (1987). After reviewing the entire record, we conclude that there is substantial evidence to support the Commission's salary adjustments in this case.

For the foregoing reasons, the Commission's order of 26 February 1993 is affirmed.

AFFIRMED.

Justice MITCHELL dissenting in part.

It is my belief that when the Virgina State Corporation Commission (VSCC) set the price that North Carolina Power (NC Power) must pay Ultra Cogen Systems (Ultra Cogen) for wholesale power, the VSCC was implementing federal law and entering an order affecting wholesale power in interstate commerce. Accordingly, I conclude that when the North Carolina Utilities Commission (NCUC), while setting North Carolina retail rates, refused to allow NC Power to recover the $1.39 million that the VSCC had ordered NC Power to pay Ultra Cogen, it unlawfully interfered with the VSCC's implementation of federal law. Therefore, I dissent from the decision of the majority to the extent that it affirms the NCUC's refusal to allow NC Power to recover the $1.39 million of costs it actually incurred by complying with the VSCC's order requiring it to purchase power from Ultra Cogen.

Under procedures established by federal law, Ultra Cogen applied to the VSCC for an order requiring NC Power to purchase wholesale power from Ultra Cogen and setting the price NC Power would pay for that power. Congress has concluded that wholesale power transactions affect interstate commerce and shall be regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act. As a cogenerator qualifying facility selling wholesale power, Ultra Cogen's sales of wholesale power are controlled by the Federal Public Utility Regulatory Policies Act of 1978 (PURPA). 16 U.S.C. § 828a-3 (1985). By enacting PURPA, Congress has delegated to the states, under mandatory guidelines esablished by the FERC, authority over wholesale transactions involving cogenerators, such as the transaction between Ultra Cogen and NC Power at issue in the present case. As a result, when VSCC set the price NC Power must pay Ultra Cogen for the wholesale power at issue here, the VSCC was implementing federal law and mak-

ing a determination affecting wholesale power in interstate commerce. The VSCC was making a determination which, but for the provisions of PURPA, would have been made exclusively by FERC; that determination was the functional and legal equivalent of an order by the FERC setting the price. For that reason, when the NCUC refused to allow NC Power to recover the $1.39 million in annual capacity costs it had actually incurred as a result of the VSCC order, the NCUC unlawfully interfered with the VSCC's implementation of federal law. In my view, the NCUC's actions were preempted by federal law and must be reversed by this Court.

The Supremacy Clause of the Constitution of the United States subordinates the legislative and administrative acts of the individual states to those of the United States.

> Pre-emption occurs when Congress, in enacting a Federal statute, expresses a clear intent to pre-empt state law when there is outright or actual conflict between Federal and state law, where compliance with both Federal and state law is in effect physically impossible, where there is implicit in Federal law a barrier to state regulation, where Congress has legislated comprehensively, thus occupying an entire field of regulation and leaving no room for the states to supplement Federal law, or where the state law stands as an obstacle to the accomplishment and execution of the full objectives of Congress. Pre-emption may result not only from action taken by Congress itself; a Federal agency acting within the scope of its congressionally delegated authority may pre-empt state regulation.

Louisiana Public Service Comm. v. Federal Communications Comm., 476 U.S. 355, 368-69, 90 L. Ed. 2d 369, 381-82 (1986) (citations omitted). I believe that the doctrine of preemption embodied in the Supremacy Clause

precludes the order entered by the NCUC and affirmed by the majority of this Court in the present case.

PURPA was adopted in 1978 as part of the National Energy Act. *Federal Energy Regulatory Comm. v. Mississippi,* 456 U.S. 743, 745, 72 L. Ed. 2d 532, 537-38 (1982). PURPA represented a response to rapidly fluctuating conditions, including an anticipation of impending shortages of essential non-renewable forms of energy. *Id.* It was intended to advance a national policy of energy conservation. *Id.* Section 210 of Title II of PURPA dealing with cogeneration was part of a broad federal statute that also set standards for retail rates for electric utilities. *Id.* Section 210 was intended to promote the development of qualified cogeneration facilities in order to reduce the demand for traditional fossil fuels. *Id.* at 750, 72 L. Ed. 2d at 541.

PURPA expressly requires the FERC to "prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production." 16 U.S.C. § 824a-3(a) (1985). The FERC is specifically required to promulgate rules requiring electric utilities to "sell electric energy to qualifying cogeneration facilities" and to "purchase electric energy from such facilities." 16 U.S.C. § 824a-3(a)(1)-(2) (1985).

In 1980, pursuant to the requirement of Section 210 (a) of PURPA, the FERC issued a series of regulations further defining federal cogeneration law and policy. Section 292.303(a) of the regulations imposes a federal obligation on electric utilities to purchase power from qualifying facilities; "each electric utility shall purchase, in accordance with [18 C.F.R. § 292.304], any energy and capacity which is made available from a qualifying facility: (1) directly to the electric utility. . . ." 18 C.F.R. § 292.303(a) (1992). Acting under PURPA, the FERC provided that a rate for such purchases satis-

fies the just, reasonable, and public interest requirement for PURPA rates if the rate equals the "avoided costs" of a utility. The FERC required that avoided costs must be derived through a mandatory consideration of specific factors. These factors include the anticipated reliability of the qualifying facility. 18 C.F.R. § 202.304(b)(2), (b)(4), (c) (1992). The FERC has also provided that such rates may be less than avoided cost "if the State regulatory authority . . . determines that a lower rate is consistent with [the just, reasonable, and public interest requirement] and is sufficient to encourage cogeneration." 18 C.F.R. § 292.304(b)(3) (1992).

The FERC regulations also contain additional provisions for establishing rates to be paid to qualifying facilities. They provide that the cogenerator shall, at its option, provide energy or capacity "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term." 18 C.F.R. § 292.304(d)(2) (1992). If the qualifying facility so decides, "the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either: (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred." *Id.*

The profound effect of PURPA on state authority is demonstrated by the FERC's comments to its 1980 regulations. There, the FERC determined that efficient use of fuels allowed cogeneration facilities to "make a significant contribution to the Nation's effort to conserve its energy resources." 45 Fed. Reg. 12,215 (1980). The FERC further concluded that Section 210 was designed to remove former obstacles to the growth of cogeneration, one of which was that utilities were not generally required to purchase the power produced by a cogenerator at an appropriate rate. *Id.* Under Section 210, each electric utility would be required "to offer to purchase

available electric energy from cogeneration and small production facilities." *Id.*

The FERC also has determined that PURPA requires cooperation between the federal government and the states. Implementation of PURPA is reserved to state regulatory authorities and non-regulated entities. 45 Fed. Reg. 12,216 (1980). In this context, the FERC has determined that "implementation means enforcing the federal obligation on electric utilities to purchase power at avoided cost rates" which expressly requires a determination of "the rate for purchases at a level . . . appropriate to encourage cogeneration." 45 Fed. Reg. 12,221 (1980). Therefore, "[s]tate laws or regulations which would provide rates lower than the Federal standards would fail to provide the requisite encouragement of these technologies, and must yield to Federal law." *Id.* The states' obligation to follow federal rate law is also reflected in the FERC's determination that when a facility "shows that it requires rates for purchases based on full avoided costs to remain viable, or to increase its output, the State regulatory authority . . . is required to establish such rates." 45 Fed. Reg. 12,223 (1980).

It was within the context of the foregoing federal statutes and regulations that the VSCC made its determination that NC Power must purchase wholesale power from Ultra Cogen at the prices the VSCC established. No one has questioned the jurisdiction of the VSCC to hear the dispute or to enter its decision. Ultra Cogen went to the VSCC rather than the NCUC because the wholesale sales at issue were to take place in Virginia. Once the VSCC entered its ruling, the obligation of NC Power to purchase wholesale power from Ultra Cogen and the price of that wholesale power were established by federal law. From that point on, neither the NCUC nor any other state agency was free to establish a different price that NC Power must pay Ultra Cogen for the wholesale power, even though it was to be resold in

North Carolina. Certainly, NC Power was not required to pay Ultra Cogen different prices for the wholesale power purchased depending on the state in which NC Power resold that power. In my view, the NCUC was without authority to indirectly subvert the VSCC's decision by refusing to permit NC Power to recover the amounts it had been forced to pay involuntarily to Ultra Cogen for the power in question by virtue of VSCC's order. Further, I do not share the apparent view of the majority, as expressed in footnote 2 of its opinion, that the failure of NC Power to devote the time and resources necessary to appealing the decision the VSCC had entered over NC Power's strong objections and contentions somehow amounted to acceptance of that decision by NC Power. NC Power was entitled, in my view, to assume that the NCUC would honor the ruling of the VSCC applying federal law.

In *Federal Energy Regulatory Commission v. Mississippi,* the Supreme Court of the United States recognized the preemptive effect of PURPA and rejected a constitutional challenge to Section 210 of PURPA. The Supreme Court recognized that the statute used "state regulatory machinery to advance federal goals," and therefore presented unusual preemption issues. *Federal Energy Regulatory Comm. v. Mississippi,* 456 U.S. at 759, 72 L. Ed. 2d at 546. The Supreme Court expressly stated in this context that "state courts have a unique role in enforcing the body of federal law," and that "state courts were directed to heed the constitutional command that 'the policy of the [F]ederal Act is the prevailing policy in every state . . . and should be respected accordingly in the courts of the State.' " *Id.* at 760, 72 L. Ed. 2d at 547 (quoting *Testa v. Katt,* 330 U.S. 386, 392-93, 91 L. Ed. 2d 967, 972 (1947) and *Mondou v. New York, N.H. & H.R. Co.,* 223 U.S. 1, 57, 56 L. Ed. 327, 349 (1912)). The Supreme Court went on to state that:

> Any other conclusion would allow the States to disregard both the pre-eminent position held by Federal

> law throughout the Nation . . . and the congressional determination that the Federal rights granted by PURPA can appropriately be enforced through state adjudicatory machinery. Such an approach, *Testa* emphasized, "flies in the face of the fact that the States of the Union constitute a nation," and "disregards the purpose and effect of Article IV of the Constitution."

Id. at 760-61, 72 L. Ed. 2d at 548 (citations omitted).

In my view, the decision of the NCUC and the opinion of the majority here conflict with the decision of the Supreme Court of the United States in *Federal Energy Regulatory Commission v. Mississippi*, to the extent that they conclude that the preemption doctrine does not apply and that the order entered by the NCUC was permissible under PURPA. When a state agency purports to carry out the intent of PURPA, it must follow federal law. When the VSCC entered its order requiring NC Power to buy power from Ultra Cogen and setting the price NC Power had to pay for that power, it was enforcing PURPA, the applicable federal law. When the NCUC disregarded the order entered by the VSCC, it prevented the VSCC's lawful order enforcing the controlling federal law established by PURPA and violated the Supremacy Clause. The NCUC assumed total control over the valuation of costs related to PURPA-mandated purchases of electric power, despite the decision by the VSCC implementing PURPA and despite NC Power's clear federal obligation to pay Ultra Cogen the amount set by the VSCC for the power NC Power was required to purchase over its strenuous objections from Ultra Cogen. The error of the NCUC in entering its order is emphasized by its statement in denying more than $1.39 million in annual costs, that "we recognize our [federal] obligation to encourage [qualified cogeneration facilities], but that is not the issue here." I do not believe that the NCUC can so easily avoid the requirements of PURPA by simply as-

serting that they do not apply. I believe that the exclusion of recovery for purchased capacity costs such as those at issue here is directly related to the federal mandate of encouragement of qualifying facilities to produce electric power and conserve the electric resources of this nation.

Because I believe that in determining the amount NC Power must pay Ultra Cogen under PURPA, the VSCC lawfully applied the federal law preempting the field, I believe that the determination of the VSCC had a preemptive effect equivalent to the preemptive effect of FERC orders establishing wholesale rates. That being the case, the VSCC order was binding on the NCUC under the theory of preemption. *See Mississippi Power & Light Co. v. Mississippi ex rel. Moore,* 487 U.S. 354, 101 L. Ed. 2d 322 (1988) (rates mandated by FERC held preemptive); *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 90 L. Ed. 2d 943 (1986) (same). In my view, the action of the NCUC was preempted by PURPA and by the essentially federal act of the VSCC in establishing the wholesale price that NC Power must pay Ultra Cogen for the power it acquired for resale to its retail consumers. Therefore, I dissent from that part of the decision of the majority holding to the contrary.

Justice WEBB joins in this dissenting opinion.

APPENDIX B

Order of the Supreme Court of North Carolina
(February 15, 1995)

SUPREME COURT OF NORTH CAROLINA

No. 230A93

STATE OF NORTH CAROLINA, *ex rel.*
UTILITIES COMMISSION

v.

NORTH CAROLINA POWER

From NC Utilities Commission
(E-22, SUB 333&5)

ORDER

Upon consideration of the petition filed by Defendant in this matter for rehearing of the decision of this Court pursuant to Rule 31, N.C. Rules of Appellate Procedure, the following order was entered and is hereby certified to the North Carolina Court of Appeals:

> "Denied by order of the Court in conference, this the 13th day of February 1995
>
> /s/ Orr, J.
> For the Court"

WITNESS my hand and the seal of the Supreme Court of North Carolina, this the 15th day of February 1995.

CHRISTIE SPEIR CAMERON
Clerk
Supreme Court of North Carolina

/s/ Marvea J. Francis
MARVEA J. FRANCIS
Assistant Clerk

[SEAL]

APPENDIX C

Order of the North Carolina Utilities Commission (February 26, 1993)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

Docket No. E-22, SUB 333
Docket No. E-22, SUB 335

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

IN THE MATTER OF
REQUEST OF NORTH CAROLINA POWER FOR AUTHORITY TO ADJUST ITS ELECTRIC RATES AND CHARGES

and

APPLICATION OF NORTH CAROLINA POWER PURSUANT TO G.S. 62-133.2 AND NCUC RULE R8-55 RELATING TO FUEL CHARGE ADJUSTMENTS FOR ELECTRIC UTILITIES

ORDER GRANTING PARTIAL RATE INCREASE

BY THE COMMISSION: On July 31, 1992, North Carolina Power (NC Power or the Company) filed an application with the North Carolina Utilities Commission seeking authority to adjust and increase its rates and charges for electric service to its North Carolina retail customers effective on August 30, 1992. NC Power is an

unincorporated division of Virginia Electric and Power Company (Vepco). On August 27, 1992, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, requiring public notice, and scheduling public hearings.

As provided by Commission Rule R8-55, NC Power's fuel adjustment application was due to be filed on September 11, 1992, and a hearing held on November 10, 1992. Docket No. E-22, Sub 335 had been reserved for the 1992 annual fuel charge adjustment proceeding.

On September 4, 1992, NC Power filed a Motion for Consolidation of Hearings in the above-captioned dockets. By its motion, the Company asserted that it intended to file supplemental data updating its testimony in the general rate case with respect to fuel costs and the fuel component of purchased power consistent with the last test period required for its annual fuel charge adjustment proceeding, which was the 12-month period ending June 30, 1992. NC Power therefore proposed that the hearing in its annual fuel charge adjustment proceeding be rescheduled and consolidated with the general rate case hearing scheduled to begin in Raleigh on January 12, 1993.

On September 11, 1992, the Company filed its annual fuel charge adjustment application. On October 5, 1992, the Commission issued an Order consolidating the rate case and fuel clause hearings. In that Order, the Commission provided that the Experience Modification Factor (EMF) shall terminate on December 31, 1992, deferred the implementation of a new EMF until the implementation of base rates in Docket No. E-22, Sub 333, and deferred the implementation of a new fuel cost rider to accommodate the implementation of a new primary fuel component in Docket No. E-22, Sub. 333. The Commission also permitted the Company's September 11, 1992 fuel filing to serve as its fuel-related data in its general

rate case pursuant to G.S. 62-133(c) and Commission Rule R1-17. Finally, the Commission provided for a consolidated public notice of the rate and fuel proceedings.

The Attorney General filed Notices of Intervention on August 25, 1992, in Docket No. E-22, Sub 333 and on January 7, 1993, in Docket No. E-22, Sub 335, pursuant to G.S. 62-20, on behalf of the using and consuming public.

On August 31, 1992, the Carolina Industrial Group for Fair Utility Rates (CIGFUR) filed a Petition to Intervene in Docket No. E-22, Sub 333, which was allowed by Commission Order dated September 2, 1992. CIGFUR also filed a Petition to Intervene in Docket No. E-22, Sub 335, on October 7, 1992, which was allowed by Commission Order dated October 9, 1992.

On October 5, 1992, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to Intervene in Docket No. E-22, Sub 333, which was allowed by the Commission on October 6, 1992. CUCA also filed a Petition to Intervene in Docket No. E-22, Sub, 335, on October 9, 1992, which was allowed by Commission Order dated October 13, 1992.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Ahoskie:	Bill Early
Elizabeth City:	Georgetta Jackson William Pruden Deborah Fox Cavenaugh Keith Fearing
Williamston:	Kenneth Perry Sheila Godard
Roanoke Rapids:	Edwin Akers

The Company presented the testimony and exhibits of the following witnesses: James T. Rhodes, President and Chief Executive Officer of Virginia Electric and Power Company; William E. Avera, a principal in Financial Concepts and Applications, Inc.; Glen B. Ross, Manager-Planning for Virginia Electric and Power Company; Maxwell R. Schools, Jr., Manager-Regulatory Accounting for Virginia Electric and Power Company; and Andrew J. Evans, Director-Rate Design for Virginia Electric and Power Company.

The Company also introduced the affidavits and exhibits of James P. Carney, Director-Financial Analysis for Virginia Electric and Power Company, and Charles R. Goode, III, Director-Regulatory Accounting for Virginia Electric and Power Company.

The Public Staff presented the testimony and exhibits of the following witnesses: John Robert Hinton, Financial Analyst, Economic Research Division of the Public Staff; Kerim Lamar Powell, Electric Engineer, Electric Division of the Public Staff; Benjamin R. Turner, Jr., Electric Engineer, Electric Division of the Public Staff; James S. McLawhorn, Electric Engineer, Electric Division of the Public Staff; Thomas S. Lam, Electric Engineer, Electric Division of the Public Staff; Kelly B. Dietz, Staff Accountant, Accounting Division of the Public Staff and Michael C. Maness, Supervisor, Electric Section, Accounting Division of the Public Staff.

CIGFUR presented the testimony and exhibits of the following witnesses: Nicholas Phillips, Jr., principal in the firm of Drazen-Brubaker & Associates, Inc., and John P. Murphy, Director of Energy Supply for Champion International.

The Company presented the rebuttal testimony of the following witnesses: Maxwell R. Schools, Jr.; Gary L. Edwards, Manager-Capacity Acquisition of Virginia Electric and Power Company; James P. Carney; Andrew J.

Evans; William E. Avera; and John F. Hughes, Jr., Outer Banks District Manager.

Prior to and during the course of the hearings, the parties made various motions and the Commission entered various Orders, all of which are matters of record. Additionally, pursuant to Orders of the Commission or requests of the parties, also of record, certain parties were directed or permitted to submit late-filed exhibits either during or subsequent to the hearings.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearing, the proposed orders and briefs submitted by the parties, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. NC Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. NC Power is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. NC Power is an unincorporated division of Virginia Electric and Power Company and has its office and principal place of business in Richmond, Virginia. Virginia Electric and Power Company is a wholly-owned subsidiary of Dominion Resources, Inc.

2. NC Power is lawfully before this Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133 and for an adjustment in its nuclear and fossil fuel costs pursuant to G.S. 62-133.2.

3. The test period for purposes of the general rate case proceeding (Docket No. E-22, Sub 333) is the 12-month period ended December 31, 1991, adjusted for certain known changes based upon circumstances and events occurring up to the close of the hearing.

4. NC Power, by its general rate case application (Docket No. E-22, Sub 333), sought an increase in its basic rates and charges to its North Carolina retail customers of $21,420,000 consisting of an increase of $22,311,000 in annual basic non-fuel revenues and a decrease in the fuel component of $891,000.

5. The overall quality of electric service provided by NC Power to its North Carolina retail customers is good. The only area of concern is in the Outer Banks, and the Company is taking appropriate action to improve its service there.

6. The Summer/Winter Peak and Average (SWPA) cost allocation method is the most appropriate method for determining the North Carolina retail jurisdictional cost of service.

7. The Summer/Winter Peak and Average (SWPA) cost allocation method is the most appropriate method for determining North Carolina retail customer class cost responsibility.

8. The appropriate level of materials and supplies for use in this proceeding is $13,090,000.

9. The appropriate level of cash working capital investment for use in this proceeding is $(2,458,000).

10. NC Power's reasonable rate base used and useful in providing service to its North Carolina retail customers is $367,831,000, consisting of electric plant in service (including nuclear fuel) of $598,046,000 and materials and supplies of $13,090,000, reduced by accumulated depreciation of $166,889,000, accumulated amortization of nuclear fuel of $36,842,000, accumulated deferred income taxes of $37,101,000, cash working capital of $2,458,000, and other cost-free capital of $15,000.

11. The appropriate level of test year North Carolina jurisdictional sales is 2,521,134 mWh.

12. The appropriate level of unbilled test year sales is 8,795 mWh.

13. The appropriate level of basic rate schedule revenues based on rates in effect as of February 14, 1991, is $134,938,156.

14. The appropriate level of basic revenue related to unbilled sales is $430,599.

15. The appropriate end-of-period level of revenues for load management credits is $(176,117), before reallocation for demand site management (DSM) considerations.

16. The appropriate end-of-period level of revenues related to facilities charges is $408,313.

17. The appropriate level of end-of-period revenues related to miscellaneous service charges is $856,470.

18. The appropriate level of revenue associated with growth, usage, and weather is calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues and test year kWh sales.

19. The mWh adjustments related to weather normalization, customer growth, and increased usage for the 12-month test period through the update period ending September 30, 1992, are (5,308) mWh, (6,447) mWh, and 144,361 mWh, respectively, for a total of 132,606 mWh. These adjustments are appropriate for use in this proceeding.

20. The basic revenue related to weather normalization, customer growth, and increased usage for the test year through the update period ending September 30, 1992, is $6,746,512.

21. The adjusted level of sales for the test year through the update period ending September 30, 1992, is 2,662,535 mWh.

22. The basic revenue related to growth in load management credits for the test period through the update period ending September 30, 1992, is $(6,126).

23. Total rate schedule revenue (excluding fuel revenue) for the test period through the update period ending September 30, 1992, is $142,115,267.

24. For the test period through the update period ending September 30, 1992, total basic adjusted revenue excluding other miscellaneous revenue is $142,683,807 based on the sum of adjusted rate schedule revenue of $142,115,267; less load management credits of $176,117, growth related to load management of $6,126, and allocated DSM cost of $514,000; plus revenue derived from facilities charges of $408,313, plus miscellaneous service revenue of $856,470.

25. The proper level of gross revenue for the Company for the test year (excluding fuel revenue) under present rates and after accounting and pro forma adjustments is $144,377,000.

26. Vepco reported that in 1986 it decided to deal with non-utility generation (NUG) offers by conducting a solicitation because it was receiving NUG capacity offers in amounts greater than its projected needs for the foreseeable future.

27. The Company instituted its solicitation process by sending out a letter on December 23, 1986, to interested developers. The letter was sent to Ultra Cogen Systems, Inc. (Ultra Cogen), at its request on January 13, 1987.

28. The Company sought 700 MW of capacity through its December 1986 solicitation. In response it received bids for 5,083 MW. The Company selected ten projects for negotiation and ultimately signed contracts in June 1987 for seven projects totaling 1,264 MW. Six of these projects are in operation with a dependable capacity of 1,412 MW. The contract for the remaining project has been terminated.

29. In March 1988, Vepco issued a formal Request for Proposals seeking 1,750 MW of capacity. It received bids for 95 projects totalling 14,653 MW. It ultimately signed contracts for 19 projects totalling 2,086 MW. Eleven projects are still active totalling 1,291 MW, seven of which currently are operational with a dependable capacity of 982.4 MW.

30. The Company undertook a solicitation for peaking power in October 1988 from which no contracts were signed. An all source solicitation for 1,100 MW was undertaken in 1989. The 1989 solicitation resulted in 11,000 MW being offered. Contracts were signed for 442 MW and Vepco announced it would build its own 400 MW coal plant. No projects from this solicitation are currently in operation.

31. The Virginia State Corporation Commission (SCC) and the Public Staff have expressed concerns about the Company's capacity planning process, including whether its decisions to buy or build have been based on questionable cost data, its failure to compare its estimated construction costs with each individual NUG project in its winning package, and its bias toward NUG capacity purchases.

32. The contracts the Company has entered into for NUG projects contain a variety of terms regarding how total costs are divided between capacity and energy costs and how capacity costs are structured. The Public Staff has expressed concerns about ratchet arrangements where higher capacity payments are paid in earlier years and lower payments are paid in the final years of the contracts.

33. The Public Staff has not evaluated the reasonableness and appropriateness of indiivdual NUG contracts resulting from the Company's various solicitations. The NUG expenses being allowed in rates as reasonable are being allowed for purposes of this proceeding only.

34. The Hadson projects were originally proposed by Ultra Cogen during the 1986 solicitation and rejected by

Vepco because the price proposed was excessive and Ultra Cogen was unwilling to accept certain terms and conditions.

35. Arbitration proceedings were initiated by Ultra Cogen's filing of eight arbitration petitions with the SCC for nine projects (two of which were in West Virginia) between November 12, 1987, and December 3, 1987, requesting the SCC to order Vepco to enter into power purchase agreements.

36. Ultra Cogen's first petition for arbitration, which was filed on November 12, 1987, involved a proposed cogeneration facility at The Lane Company, Inc. (Lane) in Altavista, Virginia (Case No. PUE870088). The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which is of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result.

37. The Virginia SCC issued a policy statement on competitive bidding on January 29, 1988, finding that PURPA does not require a utility to offer full administratively determined avoided cost to qualifying facilities (QFs) and that avoided costs could be determined through competitive bidding.

38. The SCC's policy statement on competitive bidding also provided that in the evaluation of specific proposals favorable weight should be assigned to the use of Virginia fuels, manpower and other state resources, the benefits to be derived by the industries and communities associated with particular projects, and other identifiable economic and societal benefits to the people of the Commonwealth of Virginia.

39. Vepco requested dismissal of the arbitration petitions on the grounds that the SCC had expressed general approval of bidding in its policy statement of January 29, 1988.

40. On February 26, 1988, one month after the SCC's policy statement on competitive bidding, the SCC issued an Order requiring Vepco to negotiate with Ultra Cogen and naming a Commissioner to serve as arbitrator.

41. Ultra Cogen and Vepco agreed that the number of projects to be considered by the SCC would be reduced to four, within Vepco's territory, with Ultra Cogen being allowed to select the four from five potential projects at a later date.

42. Vepco's position in the arbitration proceedings was that the prices resulting from the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to set the prices in the Ultra Cogen contracts. The arbitrator disagreed.

43. The Virginia arbitrator required the prices for these projects to be based on Vepco's costs of its Chesterfield 7 as those costs were projected on November 12, 1987, the date the first petition for arbitration was filed.

44. Vepco analyzed the projected capacity and energy costs of a unit similar to Chesterfield 7 over a 25-year period.

45. The payments that correspond to the arbitrator's directive were established in the arbitrator's Interim Order dated May 27, 1988, along with other key terms and conditions to be included in a power purchase agreement between the parties. The capacity payments for the Hadson projects were set at $341/kW for the first 15 years.

46. Ultra Cogen's energy prices were established based on the assumption that coal prices would be increasing in the future. Vepco's fuel reports on file with this Commission show that from 1984 through 1987 the

cost of coal decreased and has remained relatively stable ever since.

47. The Award and Final Order issued in the arbitration proceedings on September 30, 1988, recognized that the agreements between the parties reflected negotiations and rulings based on the unique circumstances of those proceedings, including that the projects involved coal-fired facilities in lesser populated areas of the Commonwealth.

48. Vepco did not appeal the SCC arbitration orders to the courts.

49. Ultra Cogen subsequently was purchased by Hadson Power and these projects became known as Hadson Power 11—Southampton, Hadson Power 12—Altavista, and Hadson Power 13—Hopewell (the Hadson projects). Hadson was recently purchased by LG&E Development Corporation. These projects are now owned by a conglomerate of limited and general partners, including subsidiaries of Westmoreland Coal and a Chrysler Capital Corporation subsidiary.

50. The Hadson Power 11—Southampton project came on line on March 7, 1992; the Hadson Power 12—Altavista project on February 22, 1992; and the Hadson Power 13—Hopewell project on July 1, 1992. The fourth project is in default.

51. Vepco is currently obligated to pay $64 million on a system basis for capacity costs under three of the four contracts that Vepco entered into with Ultra Cogen as a result of the arbitration proceedings before the Virginia SCC.

52. Vepco did not file any information with this Commission concerning the arbitration proceeding or the resulting capacity costs associated with the arbitrated projects until this proceeding.

53. Vepco has not filed the contracts for the Hadson projects or otherwise sought Commission approval of the capacity or energy costs of the projects except in its application in this rate case.

54. The average capacity cost of the 1986 projects is $141/kW. If this capacity cost were used to adjust the Hadson projects' capacity costs of $341/kW, $1.63 million of the capacity costs would be unreasonable and subject to disallowance.

55. The average capacity cost of the 1988 projects is $171/kW. If this capacity cost were used to adjust the Hadson projects' capacity costs of $341/kW, $1.39 million of the capacity costs would be unreasonable and subject to disallowance.

56. The same Virginia Commissioner who served as arbitartor in the proceeding involving the Ultra Cogen projects issued an Order in 1990 concerning Doswell Limited Partnership's application for approval of the construction of a 650 MW NUG project. This Order indicated that Doswell's anticipated contractual payments were based upon the avoided costs of Chesterfield 7 and that these contractual payments were considered reasonable. The capacity costs for the Doswell project sought to be recovered in this proceeding are $146/kW.

57. This Commission is not bound by actions of the SCC with regard to the Hadson projects.

58. While the average capacity cost for the 1986 solicitation could be used to adjust the capacity costs for the Hadson projects, the average capacity cost for the operational projects resulting from the 1988 solicitation is more appropriate.

59. It is appropriate to reduce the Company's operation and maintenance expense by $1,390,000 to reflect unreasonable purchased capacity costs.

60. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended in whole or in part to compete with natural gas utilities or w th other energy providers. The amount of these advertising costs to be removed in this case totals $54,000.

61. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended to promote the sale of electricity in a manner inconsistent with the provisions setting forth the allowable types of such advertising in Commission Rules R12-12 and R12-13. The amount of these advertising costs to be removed in this case totals $11,000.

62. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended to enhance the Company's image or to achieve other objectives not related to the provision of safe and reliable electric utility service. The amount of these advertising costs to be removed in this case totals $13,000.

63. The Public Staff adjustment to exclude $28,000 from expenses, representing 50% of the North Carolina retail portion of the compensation of the officers most closely linked with meeting the demands of the Company's common stockholder, is reasonable and appropriate for purposes of this proceeding.

64. The Public Staff adjustment to remove $10,000 related to community and government affairs projects and $89,000 of other charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

65. The Public Staff adjustment to increase operation and maintenance expense by $41,000 to reflect common stock issuance costs is reasonable and appropriate for purposes of this proceeding.

66. The level of operation and maintenance expense (other than fuel) under present rates appropriate for use in this proceeding is $75,065,000.

67. It is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 3 loss amortization of $1,306,000 from depreciation and amortization expense. It is also reasonable and appropriate to establish a rate rider of 0.066328¢/kWh, to expire one year from the date of this Order, for the purpose of allowing the Company to recover the remaining unamortized loss.

68. The level of depreciation and amortization expense appropriate for use in this proceeding is $20,606,000.

69. The level of other tax expense present rates appropriate for use in this proceeding is $11,100,000.

70. The Public Staff adjustment of $(4,000) to reflect the use of an average North Carolina state income tax surcharge rate of 1.5% is reasonable and appropriate for purposes of this proceeding.

71. Based on the other findings and conclusions set forth in this Order, the appropriate level of income tax expense under present rates for use in this proceeding is $8,607,000.

72. The level of other interest expense appropriate for use in this proceeding is $208,000.

73. The level of interest on tax deficiencies appropriate for use in this proceeding is $171,000.

74. The reasonable level of test year operating revenue deductions for NC Power (excluding fuel expense) after normalization and pro forma adjustments, under present rates is $115,757,000.

75. The proper capitalization ratios for use in this proceeding are as follows:

Long-Term Debt	45.227%
Preferred Stock	9.955%
Common Equity	44.818%
Total	100.000%

76. The proper embedded cost rates of long-term debt and preferred stock for use in this proceeding are 8.024% and 5.598%, respectively.

77. Estimates of the cost of common equity capital derived by use of both the constant growth form of the discounted cash flow (DCF) model and the FERC risk premium model should be accorded the greatest weight in determining the appropriate cost of equity in this proceeding.

78. The non-constant growth DCF model and the risk premium methods employed by witness Avera should be accorded only minimal weight in this proceeding.

79. The Company does not plan a public offering of its common stock in the near future.

80. In a foregoing finding of fact, an adjustment has been made to the cost of service for actual jurisdictional test-year expenses associated with the Company's stock purchase plans. No further adjustment to cost of service, rate base, or cost of capital to compensate for flotation costs is appropriate.

81. The appropriate cost of common equity for use in this proceeding is 11.80%.

82. Combining the capitalization ratios and the cost rates for each component of capital adopted for use herein, the Commission finds that the rate of return which the Company should be allowed an opportunity to earn on its rate base is 9.48%.

83. NC Power should be authorized to increase its annual level of gross revenues under present rates by

$10,642,000 (excluding fuel revenue). After giving effect to the approved increase, the annual revenue requirement for NC Power (excluding fuel revenue) is $155,019,000, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

84. The revenue increase adopted herein should be distributed to the various customer classes as follows:

	Rate of Increase Index
Residential	1.125
Small General Service	1.0
Large General Service	0.875
Outdoor Lighting	1.0
Traffic Signals	1.0
Overall	1.0

85. The summer/winter differential of 1.0¢/kWh is appropriate for setting residential non-time of use rates in this case.

86. The basic customer charge for residential non-time of use rates should be set to a level of $9.50 per month in designing rates to produce the level of revenue found appropriate for the residential rate class in this case.

87. NC Power proposed a new Line Extension Plan as part of its original filing in this proceeding. The plan was subsequently modified during the hearing by means of a stipulation between the Company and the Public Staff regarding revised language that would permit a residential customer to request overhead construction rather than underground construction in the application of the revenue test.

88. The proposed new Line Extension Plan will recover approximately $1 million per year more from new residential customers and approximately $75,000 per year more from new non-residential customers.

89. More complete recovery of investment in new distribution plant will help delay future general rate increases, and it will avoid much of the investment for new customers that has been charged to existing customers.

90. Overhead line extensions should continue to be available to customers requesting overhead service, and associated construction costs should be determined on a case-specific basis.

91. The proposed new Line Extension Plan, as modified during the hearing, is appropriate and should be approved to become effective 90 days after the date of this Order.

92. The Company offers a reduction to residential energy and demand charges for customers whose dwellings meet certain thermal integrity requirements.

93. Historically, the thermal requirements to qualify for the reduction have been substantially more stringent than those required by the North Carolina Building Code for all residential construction.

94. The North Carolina Building Code Council has adopted new residential building standards to be effective April 15, 1993, which are substantially more stringent than those currently in place.

95. NC Power has agreed to file new revised standards to qualify for the residential conservation reduction (RCR) prior to April 15, 1993.

96. It is appropriate to modify Schedule 6C, Schedule SG, and Schedule CS to allow for two curtailment requests per day during the winter season as proposed by the Company.

97. The rate designs and rate schedules proposed by the Company are reasonable and appropriate except as specifically modified herein.

98. The change proposed by the Company to paragraph II.A.1 of the Company's Terms and Conditions for the delivery of electric service rules and regulations has been withdrawn at this time and should not be approved.

99. The Terms and Conditions proposed by the Company are reasonable and appropriate except as specifically modified herein.

100. The test period for the fuel clause proceeding (Docket No. E-22, Sub 335) is the 12-months ending June 30, 1992.

101. The fuel proceeding test period per book system sales are 57,794,906 mWh.

102. The fuel proceeding test period per book system generation is 61,448,089 mWh which includes various energy generations as follows:

	mWh
Coal	25,992,366
Internal Combustion	1,413,808
Heavy Oil	1,912,993
Natural Gas	87,836
Nuclear	22,978,300
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,268,968
Other	5,234,861
Interruptible Sales	(2,551,212)

103. The normalized system nuclear capacity factor which is appropriate for use in this proceeding is 69.24%.

104. The normalized generation is based on the 12-month test period ending June 30, 1992.

105. The adjusted test period sales of 58,613,478 mWh results from an additional 280,695 mWh of customer growth, 183,088 mWh of additional customer

usage, and an additional 354,789 mWh associated with weather normalization added to fuel test period system sales of 57,794,906 mWh.

106. The adjusted test period system generation for use in this proceeding is 62,309,169 mWh which includes various energy generations as follows:

	mWh
Coal	28,130,404
Internal Combustion	1,530,090
Heavy Oil	2,070,346
Natural Gas	95,061
Nuclear	20,474,196
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,784,633
Other	5,665,469
Interruptible Sales	(2,551,212)

107. The appropriate fuel prices for use in this proceeding are as follows:

A. The coal fuel price is $14.26/mWh.

B. The nuclear fuel price is $4.59/mWh.

C. The heavy oil fuel price is $24.90/mWh.

D. The natural gas price is $30.59/mWh.

E. The internal combustion turbine (IC) fuel price is $21.33/mWh.

F. The fuel price for other purchased and interchanged power is $15.12/mWh.

G. The total fuel cost for interruptible sales is $28,446,000.

H. Hydro, pumped storage, and non-utility generation (NUG) have a zero fuel price.

108. The adjusted system fuel expense for the July 1, 1991, to June 30, 1992, test period for use in this proceeding is $639,430,000.

109. The appropriate base fuel factor for this proceeding is 1.091¢/kWh, excluding gross receipts tax.

110. The Company's North Carolina test period jurisdictional fuel expense overcollection is $1,308,510. The adjusted North Carolina jurisdictional test year sales are 2,629,412 mWh.

111. Interest expense associated with the overcollection of test period fuel revenues amounts to $218,085, based upon a 10% annual interest rate.

112. The Company's Experience Modification Factor (EMF) and interest combine for a decrement of 0.058¢/kWh, excluding gross receipts tax.

113. The final fuel factor is 1.033¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact is contained in the Company's application and in the Commission's record. These findings are generally informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Company witnesses Rhodes and Hughes and the public witnesses who appeared in Ahoskie, Elizabeth City, Williamston, and Roanoke Rapids. The only witness to complain about service was public witness William Pruden, who addressed service reliability on the Outer Banks. Witness Pruden was particularly concerned about multiple interruptions, or "blips", in the service. Witness Hughes acknowledged that the Outer Banks present a special problem for the Company and described the steps NC Power is taking to overcome these problems, including spraying of the lines to remove storm driven salt

spray. Based on the single complaint of witness Pruden as compared to the multiple witnesses praising the Company, and on the steps the Company is taking to address the Outer Banks situation, the Commission concludes that NC Power is providing good service to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence as to the reasonableness of the allocation of the Vepco system cost to the North Carolina retail jurisdiction is found in the testimony and exhibits of Company witness Evans, Public Staff witness Turner and CIGFUR witness Phillips.

Both Company witness Evans and Public Staff witness Turner recommended the use of the Summer/Winter Peak and Average (SWPA) method for determining jurisdictional allocation and the revenue requirement for the North Carolina retail jurisdiction. CIGFUR witness Phillips did not agree.

As discussed elsewhere herein, the Commission concludes that the SWPA method is the most appropriate cost allocation method for determining jurisdictional allocation and the revenue requirement for the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence as to the most reasonable method for determining North Carolina retail customer class cost responsibility is found in the testimony of Company witness Evans, Public Staff witness Turner, and CIGFUR witness Phillips.

While the Company's witness recommended the use of the Summer/Winter Peak and Average (SWPA) method for determining jurisdictional cost responsibility and revenue requirement, he recommended that the Average and

Excess method (A&E) be used to determine customer class cost responsibility. The Public Staff witness recommended that the SWPA method be used to determine both jurisdictional cost responsibility and customer class cost responsibility. The witness for CIGFUR agreed with the Company that the SWPA method was not appropriate for determining customer class cost responsibility.

Witness Evans explained that the factors to be considered in allocating the generating or production cost of the system among its customers should be consistent with the production cost each customer class load imposed on the utility. This system cost is a function of peak loads, which require a utility to build or purchase capacity, and of energy consumption, which dictates the type of plant to be built or the type of power to be purchased. Base load plants require high capital costs but have lower fuel costs and are expected to operate many hours a year. Peaking plants have low capital costs but have high fuel costs and operate for only a few hours a year. Intermediate plants have moderate capital costs and fuel costs and operate many more hours than peaking units but fewer hours than base load units. The type of plant the Company builds is based on total costs, including both fixed and variable costs. The decision to build base load capacity is expected to reduce operating costs through the use of lower heat rates and lower cost fuel; therefore, the cost of base load capacity should be viewed as having been incurred, at least in part, to provide lower cost energy. Witness Evans stated that he believed the demand allocation factor should be energy weighted in some fashion in order to recognize that the annual kWhs consumed have capacity costs associated with them.

Witness Evans testified that all customers benefit from the diversity in usage patterns that arises from serving a variety of customer classes because such diversity results in a reduction in total capacity requirements for the system. He pointed out that the total system peak load is always less than the sum of the individual customer class

peak loads, reflecting the diversity of usage patterns. He proposed that such customer class diversity should be recognized in the cost allocation process by utilizing the maximum peak load for each class as an allocation factor rather than the load for each class at the time of the system peak. The use of the class peak loads rather than the coincident peak loads for each class is what distinguishes the A&E method from the SWPA method.

Witness Evans testified that a weakness of the SWPA method was its use of both summer and winter peaks, and he insisted that the Company's summer peak alone is the driving criteria behind the Company's capacity expansion plan. He contended that the SWPA method would allow a customer class to increase its contribution to one seasonal system peak while decreasing its contribution to the other seasonal system peak as a means of reducing its overall demand related allocation factor.

Public Staff witness Turner recommended that the Commission continue to approve the SWPA cost allocation method for use in determining both jurisdictional and customer class cost responsibility in this case. He stated that this method has been approved by the Commission in the Company's previous two proceedings since 1983: Docket Nos. E-22, Sub 273 and 314. The method has also been approved for use in all CP&L general rate cases since 1982: Docket Nos. E-2, Sub 444, Sub 461, Sub 526, and Sub 537.

Witness Turner explained that the SWPA method uses an allocation factor based on two components weighted by system load factor. The first component is based on the average of summer and winter peaks at the time of the system's peak demand. The second component is based on average demand for the year. System load factor is used as a proxy for determining the portion of plant allocated by average demand. Although the amount of production capital required to produce energy is not precisely known, use of load factor as a proxy works well

in this regard because it will allocate more plant by average demand as the load factor increases and less plant as the load factor decreases. Similarly, as the Company's system load factor increases system planning will tend to meet additional load requirements with base load capacity. Conversely, as system load factor declines system planning will tend toward peaking units to meet additional load requirements.

Witness Turner stated that an analysis of investment in generating plant required to meet the system minimum load shows that approximately 60% of the Company's total production plant investment is required to meet the system's minimum load. The minimum load of 4,132 MW maintained continuously equates to an energy requirement of 36,196,320 mWh. To meet this demand or to produce this minimum energy requirement, the Company dispatches its most efficient units, which also are the units with the greatest investment per MW. The investment in these units represents approximately 60% of the Company's total investment in production plant.

Witness Turner explained that the SWPA allocation method recognizes that generating units are built to run for varying periods of time and that the increased cost to build base load units is related to average demand or energy. Peaking units, costing in the order of $400 to $500 per kW, are built to run only during the times of peak demands. These units have the lowest capital cost and highest fuel cost and are not considered economical to run except for a few hours a year. Base load units, costing in the range of $1,000 to $2,000 per kW, require the largest capital investment but have the advantage of low fuel cost (0.5 to 1.5¢/per kWh.) They are proven economical because of the required long running time. The difference in capital cost is, therefore, related to the long run time or total energy produced. Because a portion of the base load unit fixed cost investment is related

to providing long running capability at low fuel cost, it is reasonable to allocate a portion of the fixed cost investment by using average demand.

CIGFUR witness Phillips testified that the SWPA method is no longer appropriate for cost allocation between customer classes. He contended that the SWPA method does not accurately reflect the cost causation of each class and is in direct conflict with demand side management programs. He stated his preference for the summer coincident peak allocation method, but indicated that if the Commission determines that energy usage should be a part of the cost allocation formula, the A&E method is more appropriate than the SWPA method.

CUCA supported the position of NC Power and CIGFUR on cost allocation, and the Attorney General supported the position of the Public Staff. CUCA insisted that all fixed costs of production plant should be classified as demand related and that any allocation of fixed costs by energy usage unlawfully discriminates against industrial customers. The Attorney General contended that CIGFUR's and CUCA's support for the A&E method reflects the fact that it produces results similar to the coincident peak method they usually support even though the A&E method includes an allocation of some fixed costs based on energy usage.

The Commission is of the opinion that the SWPA method should be retained in this proceeding for cost allocations between jurisdictions and between customer classes. The Commission is not persuaded that the diversity in class usage patterns provides sufficient justification for utilizing class maximum peaks in the allocation formula rather than class coincident peaks. The class coincident peaks are also a measure of diversity between classes, and they are related to the needs of the entire system as a whole. This becomes significant in view of the fact that generating units are designed to meet the

needs of the entire system as a whole, not the needs of any individual class of customer. Since the only real difference between the A&E method and the SWPA method is the use of class maximum peaks by the A&E method and the use of class coincident peaks by the SWPA method, the SWPA method better reflects the diversity between class usage patterns as related to the system as a whole.

The Commission is also not persuaded in this proceeding that the allocation formula should exclude consideration of energy usage as suggested by CIGFUR and CUCA. The reasons remain the same as explained in previous general rate orders for both NC Power and for Carolina Power & Light Company. In brief, large base load generating units, which constitute the lion's share of the fixed cost investment in generating plant, are designed to achieve lower operating costs over their entire period of operation. While operation of such base load units is essential during peak periods, the large fixed cost investment in such units can only be justified by the savings in operating costs for such units during nonpeak periods.

The Commission is also not persuaded that use of both the summer coincident peak and the winter coincident peak for the demand related allocation factor is a weakness in the SWPA method. Use of only a summer coincident peak or only a winter coincident peak could give some customer classes a free ride, due to the fact that some classes may contribute greatly to one of the peaks and hardly anything to the other.

Company witness Evans testified that determination of an allocation method for fixed costs of production should also consider how fuel costs are recovered. He indicated that an allocation method should match the recovery of fixed costs with the average recovery of fuel costs. He recommended in his rebuttal testimony that if the Commission adopted the SWPA method for cost allo-

cation between customer classes in this proceeding, an additional $1.3 million should be allocated to all classes except the Large General Service (LGS) class in order to compensate the LGS class for the fact that most of the LGS class kWh usage comes from low fuel cost generation. However, he agreed on cross-examination that if a greater share of low cost nuclear fuel is allocated to the LGS class, then a greater share of nuclear decommissioning cost should be allocated to them as well.

CIGFUR witness Phillips testified that if the adopted cost allocation method is premised on the theory that some customer classes utilize more of the base load generating plants than others, then the lower energy costs resulting from those base load plants should also be allocated to those classes. He stated that there should be symmetry between allocation of fixed costs and energy related costs in any method. He contended that if the Commission allocates a greater share of the fixed costs of base load units to the LGS class, then the LGS class should be allocated a greater share of the low fuel costs from those base load units.

In response to the Company's and CIGFUR's concern about fuel allocation under the SWPA method, witness Turner stated that the Public Staff would be receptive to proposals to charge different energy costs to different customer classes. He explained that the information needed to do such an allocation would have to be provided by the Company and would have to include such data as the load shape for the various customer classes and the amount of fuel cost associated with each plant supplying power to those customer classes. In response to questions on re-direct, witness Turner stated that information needed to make recommendations on cost of service comes from the Company. In this case the Company filed Commission-ordered cost studies, but it did not file a fuel allocation study, and it has not been ordered to do so by the Commission.

The Commission concludes that the Company should make a study of the fuel costs and other energy costs incurred to serve the LGS customer class relative to the remainder of the system. The study should also attempt to determine the fixed costs of generating units required to serve the LGS customer class relative to the remainder of the system to the extent it is feasible to do so. The studies may be based upon the fixed costs and variable costs of the generating units actually dispatched to serve the LGS class load, or they may be based upon a production simulation model or other method agreed upon between the Company and the Public Staff. The Commission is further of the opinion that the Company and the Public Staff should attempt to agree on mutually acceptable criteria for making the studies, and that they should seek appropriate input and comment on making the study from CIGFUR, CUCA and any other party to this proceeding who desires to participate. The results of the studies and supporting workpapers should be filed with the Commission and the Public Staff within 12 months after the date of this Order. The Company should also file quarterly reports with the Commission regarding the progress of the studies and agreements as to study criteria and methodology, with the first report due approximately three months after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The amount of materials and supplies proposed by both the Public Staff and the Company is $13,090,000.

Based on the foregoing, the Commission concludes that the appropriate level of materials and supplies for use in this proceeding is $13,090,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The amount of cash working capital investment proposed by both the Public Staff and the Company is $(2,458,000).

Based on the foregoing, the Commission concludes that the appropriate level of cash working capital investment for use in this proceeding is $(2,458,000).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The rate base proposed by both the Public Staff and the Company is $367,831,000.

Based on the foregoing, the Commission concludes that the Company's reasonable rate base used and useful in providing service to its North Carolina retail customers for purposes of this proceeding is $367,831,000, made up of the following components:

Item	Amount (000's)
Electric plant in service including nuclear fuel	$598,046
Accumulated depreciation	(166,889)
Accumulated amortization of nuclear fuel	(36,842)
Net electric plant in service	394,315
Materials and supplies	13,090
Cash working capital	(2,458)
Accumulated deferred income taxes	(37,101)
Other cost-free capital	(15)
Total rate base	$367,831

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-17

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and was not opposed by any party.

The testimony and exhibits of witness Evans show the level of sales and revenues for the test period ending December 31, 1991, through the update period ending September 30, 1992, as follows:

Sales	mWh
North Carolina jurisdictional sales	2,521,134
Unbilled sales	8,795

Basic Revenues	Amount
Basic rate schedules	$134,938,156
Unbilled revenues	430,599
Load management credits	(176,117)
Facilities charges	408,313
Miscellaneous service charges	856,470
Total	$136,457,421

There is no other evidence in the record contesting the level of sales and revenues discussed above. The Commission concludes that these levels are reasonable for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-21

The evidence for these findings of fact is based on the testimony and exhibits of Company witness Evans and Public Staff witness Turner.

Witness Evans filed testimony and exhibits adjusting per book sales and revenues related to whether normalization, customer growth, and increased usage for the test period ending December 31, 1991, through the update period ending September 30, 1992. Witness Evans' ad-

justment is $6,746,512 based on an adjustment of 132,606 mWh of additional sales. The Public Staff accepted these numbers.

The Commission concludes that the adjustment for weather normalization, customer growth, and increased usage is reasonable and appropriate for use in determining the end-of-period level of kWh sales and revenues. The appropriate adjustment to revenues for the period ending December 31, 1991, through the update period ending September 30, 1992, due to weather normalization, customer growth, and increased usage is $6,746,512 based on additional sales of 132,606 mWh.

Based on the foregoing conclusions, for the test period ending December 31, 1991, through the update period ending September 30, 1992, the reasonable and appropriate adjusted level of sales is as follows:

	mWh
North Carolina Jurisdictional Sales	2,521,134
Unbilled sales	8,795
Weather normalization	(5,308)
Customer growth	(6,447)
Increased usage	144,361
Total	2,662,535

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-24

With the exception of the allocation of DSM cost, the evidence in the record supporting these findings of facts is contained in the testimony and exhibits of Company witness Evans and was not contested by any party. The evidence in the record as to the appropriate assignment of DSM cost is found in the testimony of witness Evans and CIGFUR witness Phillips.

Company witness Evans filed supplemental testimony proposing an adjustment to North Carolina jurisdictional

expenses based on the DSM Cost Recovery Joint Stipulation between NC Power and the Public Staff in Docket No. E-100, Sub 64. The adjustment allocates certain DSM revenue credits to the North Carolina jurisdiction whereas the Company's original filing directly assigns the credits. The adjustment of $(514,000) is the difference in the expenses allocated and directly assigned.

CIGFUR witness Phillips testified that because cost could be directly assigned, it is unnecessary to allocate DSM costs. Witness Phillips argued that allocation of cost should be used when booked data necessary to determine cost responsibility does not exist.

Based on the evidence in the record, the Commission concludes that allocation of DSM credits as proposed by the Company is reasonable and appropriate. The Commission concludes that allocation of system-wide DSM costs is appropriate because all customer classes and jurisdictions benefit from DSM programs. While all classes may not participate in a particular DSM program, all classes do benefit from the overall benefits of DSM. It is therefore equitable for all classes to bear a portion of the cost of DSM programs. Thus, the DSM related adjustment of $(514,000) is reasonable.

Based on the foregoing conclusions and the Commission's previous conclusions, the Commission now concludes that the reasonable and appropriate level of end-of-period revenues, excluding other miscellaneous revenue, for the test period ending December 31, 1991, through the update period ending September 30 , 1992, is $142,683,807 as shown below:

	Amount
Basic rate schedule revenues	$134,938,156
Unbilled revenues	430,599
Weather normalization, customer growth and increased usage revenues (including growth in load management)	6,746,512
Subtotal	142,115,267

Load management credit	(176,117)
Load management growth	(6,126)
DSM cost allocation adjustment	(514,000)
Facilities charges	408,313
Miscellaneous service charges	856,470
Total	$142,683,807

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the exhibits and other data and records filed by the Company in this proceeding. In addition to the end-of-period revenue of $142,683,807, found reasonable and appropriate in the Evidence and Conclusions for Findings of Fact Nos. 22-24, the Company recorded during the test year $1,824,000 in other miscellaneous revenue. Additionally, the Company made an adjustment of $(159,000) to annualize pole attachment revenue and adjustments totalling $28,000 to annualize Old Dominion Electric Cooperative reserve revenue. No party contested the inclusion of either the per books other miscellaneous revenue or the adjustments made by the Company.

The Commission therefore concludes that the proper gross revenue for the test year (excluding fuel revenue) under present rates and after accounting and pro-forma adjustments is $144,377,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-33

The evidence for these findings of fact is found in the testimony of NC Power witnesses Rhodes and Ross and Public Staff witness Powell. The prefiled revised testimony of Company witness Ross indicated that during the period December 28, 1990, through November 30, 1992, 16 additional NUGs declared commercial operation with a combined summer capability of 1,760 MW. These

NUG projects and their commercial operation dates were listed on his Exhibit GBR-1, Schedule 6, revised. These are as follows:

NUG Additions	Date On-line
Battersea Dam	12/31/90
Richmond Power Enterprises	03/13/91
Dale	03/29/91
Wythe Park Power #3	07/29/91
I-95 Landfill	01/01/92
Hadson #12—Altavista	02/22/92
Hadson #11—Southampton	03/07/92
Cogentrix of Richmond #1	05/01/92
Doswell #2	05/03/92
North Branch Project	05/05/92
Doswell #1	05/10/92
Commonwealth Atlantic LP	06/05/92
Harvell	06/30/92
Hadson #13—Hopewell	07/01/92
Cogentrix of Richmond #2	08/01/92
Mecklenburg	11/06/92

NC Power witness Rhodes testified that in 1986 Vepco decided to deal with NUG offers by conducting a solicitation because it believed it was receiving NUG capacity offers in amounts greater than its projected needs for the foreseeable future. The Company instituted its solicitation process by sending out a letter on December 23, 1986, to all developers with whom the Company had contact or who had shown an interest in executing a purchased power agreement with the Company.

Witness Rhodes further testified, in response to questions from the Public Staff on cross-examination, that the Company sought 700 MW of capacity through its December 1986 solicitation and received bids of 5,083 MW in response. The Company selected ten projects for negotiation and ultimately signed contracts in June 1987 for seven projects totaling 1,264 MW. Six of these projects are in operation with a summer capacity rating of 1,305

MW and an average capacity rating of 1,412 MW. Vepco's status report filed on August 30, 1992, in Docket No. E-100, Sub 41, indicates that the one remaining project from the 1986 solicitation was placed in default on July 23, 1991.

In March 1988, Vepco issued a formal Request for Proposals seeking 1,750 MW of capacity. It received bids for 95 projects totalling 14,653 MW. It ultimately signed contracts for 19 projects totalling 2,086 MW. Eleven projects are still active totalling 1,291 MW, seven of which currently are operational with a dependable capacity of 982.4 MW.

Witness Rhodes further testified that the Company undertook a solicitation for peaking power in October 1988, from which no contracts were signed. An all-source solicitation for 1,100 MW was undertaken in 1989, which resulted in 11,000 MW being offered. Contracts were signed for 442 MW and Vepco announced it would build its own 400 MW coal plant. No projects from this solicitation are currently in operation.

In response to cross-examination questions from the Public Staff, NC Power witness Rhodes conceded that the Virginia SCC had expressed significant concerns about the Company's capacity planning process, including whether its decisions to buy or build have been based on questionable cost data, its failure to compare its estimated construction costs with each individual NUG project in its winning package, and its bias toward NUG capacity purchases.

In response to cross-examination by the Public Staff, witness Rhodes also stated that the Company did not use a Company-built option for a direct comparison on a unit-by-unit basis in the spring of 1988 solicitation. He explained that what the Company did was make sure that the package of NUG projects for which Vepco signed contracts was cheaper than the amount it would have cost

the Company to have built that capacity itself. He agreed on cross-examination that there was a significant risk that the low-priced winning bidders could fall out leaving the Company only with the relatively high-priced ones.

With regard to the concerns of the Public Staff, witness Powell testified that the contracts the Company has entered into for NUG projects contain a variety of terms regarding how total costs are divided between capacity and energy costs and how capacity costs are structured. Of particular concern to witness Powell were the ratchet arrangements where higher capacity payments are paid in earlier years and lower payments are paid in the final years of the contracts.

Witness Powell also testified that the Public Staff had not evaluated the reasonableness and appropriateness of individual NUG contracts resulting from the Company's various solicitations. He indicated that the Public Staff had focused on the reasonableness of the NUG expenses at issue in this proceeding.

On May 7, 1987, the Commission entered an Order in Docket No. E-100, Sub 53, established standard rates and contract terms for qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and G.S. 62-156(b). In that Order, the Commission stated that:

> Negotiated contracts between a utility and a qualifying facility should, upon execution, be submitted to the Commission. The Commission will conduct a general review of such contracts to determine whether they comply with the provisions of this Order. If it appears that they do, such contracts will be approved for filing with the Commission. The Commission may, on its own motion, conduct further, more detailed review of the contracts at that time by way of such hearings or other proceedings as it may order. Further, such contracts, after being

approved for filing, shall be subject to review in the context of the utility's next filed general rate case or by a complaint proceeding, just as would any other contract by the utility. By this procedure, the Commission seeks to ensure that a meaningful and public review is conducted with respect to such contracts.

The Public Staff, through witness Powell, states that it has not evaluated the appropriateness of any of the individual NUG contracts at issue in this proceeding; i.e., those projects currently in commercial operation. The Public Staff has raised a number of concerns regarding the reasonableness of the various NUG contract terms related to capacity payments. According to our Order in Docket No. E-100, Sub 53, the contracts in question should have been investigated in this rate case. The Public Staff was, however, apparently unable to evaluate NC Power's NUG contracts during the course of its investigation. That being the case, the Commission hereby requests the Public Staff to investigate the contracts in question and any other NUG contracts for projects which begin commercial operation after the date of this Order and present the results of such investigation during NC Power's next general rate case in order to ensure that a meaningful and public review has been conducted. Until such time as the NUG contracts in question have been investigated by the Public Staff, the Commission finds good cause to include in rates, as recommended by the Public Staff, a reasonable and representative level of NUG capacity costs for purposes of this proceeding only.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-59

The evidence for these findings of fact is found in the testimony of Company witnesses Ross and Edwards, the testimony of Public Staff witness Powell, and exhibits associated with their testimony.

Company witness Ross testified that during the period December 28, 1990, through November 30, 1992, 16 additional NUGs declared commercial operation. Public Staff witness Powell testified that he examined the reasonableness of the NUG capacity payments that NC Power has requested in this proceeding. He recommended an adjustment with respect to three NUG projects, which will be referred to hereinafter as the Ultra Cogen projects or the Hadson projects.[1] Vepco entered into the three contracts at issue with Ultra Cogen Systems, Inc., (Ultra Cogen) as a result of arbitration proceedings before the Virginia State Corporation Commission (SCC). Vepco currently is obligated to pay $64 million on a system basis for annual capacity costs for the three Hadson projects and is seeking to recover the North Carolina retail jurisdictional allocation of these costs, approximately $2.8 million. The Public Staff recommends that $1.39 million of these capacity costs be disallowed for ratemaking purposes in North Carolina. A history of these projects is necessary to understand the issues presented.

Vepco's December 1986 solicitation letter was sent to Ultra Cogen, at its request, on January 13, 1987. Ultra Cogen proposed nine projects. Ultra Cogen's proposals were rejected in March 1987 because the proposed price was excessive and Ultra Cogen was unwilling to accept certain terms and conditions. Vepco offered to purchase energy only from Ultra Cogen, and it suggested that Ultra Cogen participate in the Company's next solicitation if Ultra Cogen wished to sell capacity. Vepco selected other proposals from the 1986 solicitation. Six of

---

[1] The projects were developed by Ultra Cogen Systems, Inc. Ultra Cogen subsequently was purchased by Hadson Power, and these projects became known as Hadson Power 11—Southampton, Hadson 12—Altavista, and Hadson Power 13—Hopewell. Hadson was recently purchased by LG&E Development Corporation. These projects are now owned by a conglomerate of limited and general partners, including subsidiaries of Westmoreland Coal and a Chrysler Capital Corporation subsidiary.

these projects have come on line, and they average $141/kW for capacity payments.

In October 1987 the Virginia SCC initiated a generic review of certain policy issues with respect to competitive bidding schemes such as Vepco's solicitation. The SCC issued a policy statement on competitive bidding in Case No. PUE870080 on January 29, 1988. In this order, the SCC concluded that federal law does not require a utility to pay full administratively determined avoided costs and that avoided costs may be determined through competitive bidding. It stated that "we believe a system of competitive negotiation such as we have described would be a very efficient and fair means of approximating real, not theoretical, avoided costs." The SCC's policy statement went on to provide that in evaluating specific proposals, favorable weight should be assigned to the use of Virginia fuels, manpower, and other State resources; the benefits to be derived by the industries and communities associated with particular projects; and other identifiable economic and societal benefits to the people of Virginia.[2] With this policy statement in hand, Vepco put together its 1988 solicitation.

While the SCC's generic review was underway, Ultra Cogen initiated arbitration proceedings for its nine projects (two of which were in West Virginia) by filing arbitration petitions with the SCC between November 12, 1987, and December 3, 1987. Ultra Cogen asked the SCC to order Vepco to enter into power purchase agreements including payments for capacity. Ultra Cogen's first petition for arbitration involved a proposed cogeneration facility at The Lane Company, Inc. (Lane) in Altavista, Virginia (Case No. PUE870088). The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were signifi-

[2] It is worth noting that this Commission lists various factors which we expect utilities to consider in negotiating with QFs, but we do not list factors such as these.

cant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result.

Vepco requested dismissal of the petitions on the ground that the SCC had expressed its general approval of competitive bidding in its January 29, 1988, Order in Case No. PUE870080. The SCC refused to dismiss and decided that it would arbitrate Ultra Cogen's petitions by Order dated February 26, 1988, one month after the SCC's policy statement on competitive bidding. The SCC stated it would approach the arbitrations in an innovative fashion, designed to deal with the subject in a prompt but effective manner. The SCC designated Commissioner Harwood to serve as arbitrator and provided that the arbitrator's conclusions would be final and that Vepco would be bound by them. The SCC ruled that the arbitration would develop appropriate contracts *for capacity purchases* by Vepco from Ultra Cogen and that the amount of the capacity to be sought by future solicitations would be limited by the amount of capacity resulting from the arbitration.

Vepco issued its 1988 solicitation letter on March 1, 1988. Vepco's position in the arbitration proceedings was that the prices resulting from the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to set prices for the Ultra Cogen contracts. (This is the position now taken by the Public Staff and opposed by the Company.) The Virginia arbitrator disagreed. By a memo issued on April 27, 1988, he required the contracts to be based on avoided costs of Vepco's Chesterfield 7 as those costs were projected on November 12, 1987, the date the first petition for arbitration was filed. This memo was issued by the arbitrator two months into Vepco's 1988 solicitation.

The arbitrator followed up just one month later with an Interim Order of May 27, 1988, in which he established capacity and energy prices, along with other key terms and conditions, for the Ultra Cogen projects. He established the capacity price at $341/kW for the first 15 years of operation. Ultra Cogen's energy prices were established based on the assumption that coal prices would increase in the future. In fact, Vepco's fuel reports on file with this Commission show that from 1984 through 1987 the cost of coal was decreasing and that it has remained relatively stable ever since. The arbitrator noted that Ultra Cogen and Vepco had agree that the number of projects would be reduced to four projects within Vepco's service territory.

Draft contracts were subsequently submitted, and the arbitrator entered his Final Order requiring Vepco to sign the contracts. In this Order, the Hearing Examiner expressly recognized that "the Agreements reflect negotiations and rulings based on the unique circumstances of these proceedings (including that they are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." Vepco signed the contracts on October 7 and 8, 1988. It did not appeal the SCC arbitration orders to the courts. Three of the four projects came into commercial operation in 1992. (The fourth project encountered permitting problems and has been placed in default).

At about the same time, Vepco signed contracts resulting from its 1988 solicitation during December 1988 and January 1989. Seven of these projects came into commercial operation in 1990 and 1992. They average $171/kW in capacity payments.

Public Staff witness Powell compared the operation of the Hadson projects, which operate at a capacity factor of 27.1%, to the projects resulting from the 1988 solicitation, which operate at a capacity factor of 35.9% The capacity costs of the Hadson projects are twice the average

costs of the 1988 projects. Witness Powell recommended that the allowable capacity costs for the Hadson projects should be the average capacity costs of the 1988 package. Consequently, he recommended that $170/kW, or $1.39 million, be disallowed. On cross-examination, he testified that he was evaluating what the North Carolina ratepayers should pay and that the costs the Company seeks to recover are too high.

Company rebuttal witness Edwards testified that this Commission should accept the Hadson capacity payments as reasonable because they resulted from arbitration before the Virginia SCC and because there is no evidence of imprudence on the Company's part. He further testified that using the costs from the projects selected from the 1988 solicitation was totally inappropriate. He conceded, however, that the Company had argued before the Virginia arbitrator that the results of the 1988 solicitation (or, alternatively the 1986 solicitation) should be used to determine the avoided costs for the Hadson projects.

The Public Staff's recommended disallowance of $1.39 million of the Hadson capacity costs raises several issues. First, the Commission must determine whether the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C.A. § 824a-3, preempts State regulatory action or otherwise binds this Commission to follow the Virginia SCC's determination of avoided costs. We conclude that it does not.

Section 210 of PURPA requires electric utilities to purchase power from qualifying cogeneration and small power production facilities (QFs). The rates for such purchases must be just and reasonable to the utility's consumers and in the public interest and they must not discriminate against QFs. PURPA provides that the rates not exceed the incremental costs of alternative electric energy, referred to in the FERC regulations as "avoided costs." 16 U.S.C.A. § 824a-3(a) and (b); 18 C.F.R. § 292.304(a) and (b) (1980). The regulations define

avoided costs as the incremental costs to a utility of electric energy or capacity or both which, but for the purchase from the QF, the utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6) (1980). Energy costs are the variable costs associated with producing electricity, such as the costs of fuel. Capacity costs are the costs associated with providing the capability to deliver electricity, primarily the capital costs of facilities. The regulations set forth certain factors to be considered in determining avoided costs. 18 C.F.R. § 292.304(e) (1980).

QFs are exempt from the Federal Power Act (with a few exceptions that are not relevant here). 18 C.F.R. § 292.601(b) (1980). Implementation of the regulations dealing with regulated utilities' obligation to purchase from QFs and the rates for such purchases is left to state regulatory authorities. 18 C.F.R. § 292.401(a) (1980). Such implementation by the states may consist of issuing regulations, undertaking to resolve disputes between utilities and QFs, or any other action reasonably designed to implement the FERC regulations. In adopting its regulations, FERC noted that it

> supports the recommendation made in the Staff Discussion Paper that it should leave to the States . . . "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

Regulations Implementing § 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12214, 12226 (1980). FERC rules afford the states "great lati-

tude"; FERC recognized that "economic and regulatory circumstances vary from State to State and utility to utility." *Id.* at 12230-1. FERC expressly acknowledged that its regulations are not intended to divest a state regulatory agency of its authority under state law to review contracts for purchases as part of its regulation of electric utilities. *Id.* at 12233.

While PURPA and the FERC regulations do not allow rates greater than avoided costs, there may be a separate basis in state law or policy for such higher rates. Virginia SCC at one time adopted the policy of considering intangible environmental and societal benefits associated with QF power. The SCC approved a 15% rider to Vepco's avoided cost tariff for the purpose of giving reasonable weight to these benefits. PURPA does not provide for the addition of such a rider. The basis for this rider was Virginia law and policy. (This Commission has never added a rider of this sort to its determination of avoided costs in North Carolina.) The 15% rider is no longer required in Virginia, but, as discussed below, it is clear that the arbitrator considered economic benefits unique to the State of Virginia in setting the Hadsen capacity payments.

Based on the foregoing, the Commission concludes that PURPA does not preempt state action. In fact, it mandates state action and expressly leaves the states flexibility to experiment and accommodate special circumstances. Thus, "avoided costs" can be determined quite differently by different jurisdictions. Further, PURPA does not preempt this Commission's authority to review QF contracts in setting rates for the electric utilities operating in North Carolina. This Commission, in setting rates for NC Power in North Carolina, is not bound to interpret PURPA in the same manner as the Virginia SCC or to provide for the SCC's consideration of benefits unique to Virginia.

A second issue raised by the Public Staff's recommendation is whether PURPA allows avoided costs to be determined by a competitive bidding procedure. In its policy statement on competitive bidding in Case No. PUE870080, the Virginia SCC concluded that the general concept of bidding for new power supplies is a permissible response to PURPA and the FERC regulations. The SCC reasoned that if competitive negotiations are properly undertaken, the costs paid by the utility are indeed its avoided costs of not dealing with another, similarly situated QF. This Commission's review of PURPA and the FERC regulations leads us to the same conclusion. The results of a competitive bidding process may be used as the soliciting utility's avoided costs.

A third issue is whether this Commission must make a finding of management imprudence in order to disallow part of the capacity costs associated with the Hadson contracts as unreasonable. Vepco takes the position that because the Virginia arbitrator ordered Vepco to sign the contracts, the Company was not imprudent and, absent a finding of management imprudence, the costs cannot be disallowed. The Public Staff asserts that expenses can be disallowed as unreasonable for a variety of reasons and that management imprudence is only one method of demonstrating unreasonableness. The Public Staff cites *State ex rel. Utilities Commission* v. *Carolina Power & Light Company*, 320 N.C. 1, 358 S.E.2d 35 (1987) (*CP&L Remand*), in which the North Carolina Supreme Court explicitly rejected CP&L's argument that absent a finding of management imprudence, the Commission was required to use CP&L's actual fuel expenses when fixing rates.

G.S. 62-133(b)(3) requires that the Commission ascertain the utility's "reasonable operating expenses" when setting rates. The Commission agrees with the Public Staff that imprudence is only one method of demonstrating that a given expense is unreasonable. Therefore it is

not improper to disallow prudently incurred but otherwise unreasonable expenses for ratemaking purposes.

For example, the Commission routinely adjusts expenses for abnormal weather, for unrepresentative nuclear capacity factors, and for customer growth. These adjustments have been upheld by the North Carolina appellate courts on several occasions. The case most specifically on point is the North Carolina Supreme Court's opinion in the *CP&L Remand* case cited by the Public Staff. This case involved the remand of a number of CP&L's general rate cases and fuel clause proceedings in the early 1980s. The remanded cases were consolidated, and several parties appealed the Commission's final order. On appeal, CP&L contended that the Commission had made no finding of management imprudence and, to the extent the Commission made findings concerning those questions, the Commission's findings were to the effect that the actions of CP&L's management were prudent. CP&L argued that "given the absence of any finding of management imprudence, the Commission was required to use CP&L's actual fuel expenses when fixing rates for the three general rate cases involved in this appeal." 310 N.C. at 11. The Supreme Court's response to this argument was: "We do not agree." *Id.* The Court cited *State ex rel. Utilities Commission* v. *City of Durham*, 282 N.C. 308, 193 S.E.2d 95 (1972), which involved the adjustment of test period fuel expenses to reflect substantially abnormal weather conditions. Although abnormal weather conditions are a factor clearly unrelated to management prudence, the Supreme Court found no error in the Commission's adjustment of test period expenses and revenue to take those abnormalities into account. The Court in the *CP&L Remand* case concluded as follows:

> Therefore, although management prudence may be an important factor considered by the Commission in a general rate case, management prudence *vel non*

> does not control the Commission's decision as to whether to adjust test period data to reflect abnormalities having a probable impact on the utility's revenues and expenses during the test period, in order that it may set reasonable rates in compliance with N.C.G.S. § 62-133.

320 N.C. at 12. The Court in fact found that the Commission had a duty to normalize or adjust expenses as necessary. *Id.*

The Commission's rule prohibiting the inclusion of political and promotional advertising in reasonable operating expenses is another example. Rule R12-13(a) provides in part:

> In ascertaining reasonable operating expenses pursuant to G.S. 62-133, no electric or natural gas utility shall be permitted to recover from its ratepayers any direct or indirect expenditures made by such utility for political or promotional advertising as defined in Rule R12-12 or for other nonutility advertising.

Rule R12-12(d) specifically excludes several types of advertising from the definition of political and promotional advertising. With regard to these exclusions, R12-13(c) provides that expenditures for these excluded types of advertising generally will be deemed to be reasonable operating expenses, but the Commission is not precluded from determining on a case-by-case basis the extent to which such expenditures exceed a reasonable level. Thus, while it may be prudent for utility management to engage in political and promotional advertising, the Commission's rule provides that the expenses for such advertising are unreasonable *per se*. Furthermore, the rule provides for the disallowance of unreasonable expenditures for other types of advertising.

Another example of the Commission determining the level of reasonable expenses without regard to the pru-

dence of the utility's actions is our decision filed on October 12, 1992, in Docket No. W-354, Sub 111, the most recent general rate case of Carolina Water Service, Inc. (Carolina Water). In this case, the Public Staff recommended that a portion of the expenses related to Carolina Water's headquarters in Northbrook, Illinois, be disallowed. Carolina Water's rebuttal evidence was to the effect that those expenses were prudent and reasonable. The Commission concluded that the level of Northbrook expenses had increased at an unreasonable level and therefore these expenses should be adjusted to a reasonable level. No finding of imprudence was made.

Other examples can be found in the present Order. In this Order we discuss several operating expenses in terms of reasonableness without any specific discussion or finding as to prudence.

Based on the foregoing, the Commission concludes that "reasonable," as used in G.S. 62-133, does not equate to "prudently incurred" and that a prudently incurred expense can be shown to be unreasonable for numerous reasons. Accordingly, the Commission rejects the Company's argument and concludes that management imprudence need not be shown for the Hadson capacity payments, or some portion of them, to be disallowed as unreasonable.

The issue to be decided is whether the level of expense for the capacity associated with the Hadson projects is reasonable for ratemaking purposes in North Carolina. The Commission concludes that it is not.

First, we need only compare the Hadson capacity payments with other, contemporaneous measures of avoided costs. Total annual capacity payments for the three Hadson projects are over $64 million systemwide. They average $341/kW. In contrast, the seven operational projects that came out of the 1988 solicitation average $171/kW. The Virginia SCC itself said that such a solicitation is a

good means of "approximating real, not theoretical, avoided costs." Vepco's 1986 solicitation produced operational projects that average $141/kW in annual capacity payments. Interestingly, the 1986 solicitation used Vepco's proposed Chesterfield 7 as a benchmark, and Vepco witness Edwards testified that "if you would publish a benchmark you'll see that most bids if not all of them will come in right at the benchmark price, and that's what we saw in the December '86 solicitation." When Chesterfield 7 was used to establish the avoided costs for the Hadson projects, it produced far higher capacity payments than when it was used as a benchmark for the 1986 solicitation. The Virginia arbitrator himself stated in a February 1990 Order that payments for the Doswell project, one of the projects from the 1986 solicitation, were based on the avoided costs of Chesterfield 7 and were reasonable. The Doswell capacity payments for this rate case are $146/kW. The Hadson payments, also based on Chesterfield 7, are $341/kW. All of this evidence tends to show that the Hadson capacity payments are out of line. The Hadson payments are also out of line with the Company's avoided costs in North Carolina. Schedule 19 sets forth this Commission's determination of Vepco's avoided costs. Schedule 19 is not directly applicable to projects the size of the Hadson projects; such large QF's must negotiate rates with the utilities. However, as a practical matter, the avoided costs set by the Commission provide a cap on negotiated rates. Based on the version of Schedule 19 approved at the time the Hadson contracts were executed, the Hadson capacity would have cost Vepco $17 million a year, rather than $64 million.

Second, it is very clear from the record in this proceeding that the SCC's treatment of the Hadson projects was directly related to expected benefits to Virginia from these projects. The arbitrator's Award and Final Order dated September 30, 1988, specifically recognizes that the Hadson contracts "reflect negotiations and rulings based on

the unique circumstances of these proceedings (including that [the projects] are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." The arbitration petition for the project at The Lane Company indicated that the facility would burn coal expected to be from or transloaded in Virgina, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the communtiy and the Commonwealth would result. These benefits flow to Virginia, not to North Carolina. For this reason, it may be reasonable for Virginians to pay the extra costs associated with the Hadson projects. But it is unreasonable for North Carolinians to pay such extra costs, and our responsibility is to set fair and reasonable rates for North Carolina. We cannot accept the assumption implicit in the Company's position that our authority to set rates for North Carolina—and, by extension, the authority of the North Carolina Supreme Court—is circumscribed by the decision of an arbitrator in Virginia.

Finally, we cannot help but note that Vepco itself argued before the Virginia arbitrator that the results of the 1988 solicitation should be used to set the capacity costs for the Hadson projects. This is exactly what the Public Staff is arguing now and the Company is opposing.

Based on the foregoing, we conclude that the capacity costs included in the arbitrated contracts for the three Hadson projects are not reasonable for ratemaking purposes in North Carolina.

In making this decision, we recognize our obligation to encourage QFs, but that is not the issue here. The issue here is ascertaining reasonable operating expenses for purposes of setting just and reasonable rates in North Carolina. We cannot find these expenses to be reason-

able for our purposes when they are well over twice contemporaneous measures of avoided capacity costs and when they were clearly influenced by economic benefits unique to the State of Virginia. This Commission also recognizes the position of Vepco. It is "caught in the middle" between our decision and that of the Virginia SCC, but that is not unique to this issue. That is an inevitable consequence of doing utility business across state lines. For example, we use a different cost allocation methodology than the Virginia SCC for purposes of allocating production costs between states, and the different methodologies mean that Vepco may collect more revenues or may collect less revenues than if both states used the same methodology. The same thing can happen any time this Commission and the Virginia SCC decide the same ratemaking issue and reach different conclusions. Still, this Commission must exercise its own judgment. Neither we nor the SCC is bound by the decision of the other.

Finally, we must determine what is a reasonable level of capacity costs for the Hadson project. Public Staff witness Powell testified that the Hadson projects should be compared to the NUG projects selected by Vepco as a result of its 1988 solicitation. He testified that there are seven operational NUG projects that were selected in the 1988 solicitation, the capacity costs for which the Company seeks to include in rates in this proceeding. These projects have a combined capacity factor of 35.9% and their average capacity cost is $171/kW. By contrast the average capacity factor for the Hadson projects is expected to be 27.1%. Powell testified that it is appropriate to compare the costs of a NUG to the costs of other NUGs and that the 1988 projects are appropriate to use because of timeliness and similar operation to the Hadson projects. He testified that it is reasonable to expect that similar operation would yield similar capacity costs. Because the capacity costs of the Hadson projects

are twice the average costs of the 1988 projects, witness Powell recommended that the allowable capacity costs for the Hadson projects should be the average capacity costs of the 1988 package. Consequently, he recommended that $170/kW, or $1.39 million, be disallowed.

Witness Powell also reviewed the projects that are in operation from the 1986 solicitation. Because of the time difference as to when the contracts were executed and other constraints, he did not include them in his calculation of the Public Staff's recommended capacity adjustment for the Hadson projects. His Exhibit KLP-1, however, shows that the six projects resulting from the 1986 solicitation have a combined capacity factor of 32.2% and that their average capacity cost is $141/kW. If the 1986 projects were used to adjust the $341/kW capacity costs of the Hadson projects, a disallowance of $200/kW (or $1.63 million) would be appropriate.

The Commission has already concluded that PURPA allows avoided costs to be determined through competitive bidding. While the average capacity cost for the 1986 solicitation could be used to adjust the capacity costs for the Hadson projects, the average capacity cost for the operational projects resulting from the 1988 solicitation is more appropriate. The projects resulting from the 1988 solicitation that are still active but not yet operational are not included in the average because there is no guarantee that they will become operational and no way to tell what their exact capacity costs will be until they come on line. Accordingly, NC Power's operation and maintenance expenses should be reduced by $1,390,000 to reflect the unreasonable portion of the capacity costs for the Hadson projects.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60-74

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witnesses Rhodes, Schools, Chamberlain, Edwards, and Carney and Public Staff witnesses Maness, Powell, and Hinton. The levels of operating revenue deductions (excluding fuel expense) proposed by the Company and the Public Staff representing their final positions are set forth in the following schedule:

(000's Omitted)

Item	Company	Public Staff	Difference
Operation and maintenance expense	$ 76,530	$ 75,011	$(1,519)
Depreciation and amortization	21,912	20,606	(1,306)
Other taxes	11,100	11,100	—
Income taxes	7,747	8,628	881
Charitable contributions	89	—	(89)
Other interest expense	208	208	—
Interest on tax deficiencies	171	171	—
Total operating revenue deductions	$117,757	$115,724	$(2,033)

As shown in the above schedule, the Company and the Public Staff agree on the amounts to be included in operating revenue deductions for other taxes, other interest expense, and interest on tax deficiencies. The Commission thus concludes that the levels of other taxes, other interest expense, and interest on tax deficiencies appropriate for use in this proceeding are $11,100,000, $208,000, and $171,000, respectively.

Operation and Maintenance Expense

The first area of difference between the Company and the Public Staff is operation and maintenance expense. The difference of $(1,519,000) is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to advertising expense	$ (132)
Adjustment to purchased capacity expense	(1,390)
Removal of 50% of selected officers' compensation	(28)
Removal of cost of community and governmental affairs projects	(10)
Adjustment to common stock issuance expense	41
Total	$(1,519)

The first adjustment made by the Public Staff concerns the appropriate amount of advertising expense. The $(132,000) difference between the parties is itemized as follows:

Item	Amount
Competitive advertising	$(108,000)
Promotional advertising	(11,000)
Image advertising	(13,000)
Total difference	$(132,000)

The advertisements at issue were set forth in Public Staff Chamberlain Rebuttal Cross-Examination Exhibit No. 1. Public Staff witness Maness made an adjustment to remove $108,000 of competitive advertising costs. In calculating his adjustment, witness Maness removed 100% of the costs of the Baby, Degree, and Gas Grill advertisements and 50% of the costs of the Company's Co-Op advertising program. Witness Maness testified that it was appropriate to consider 50% of the costs of Co-Op advertising to be costs of advertising intended in whole or in part to compete with natural gas companies or with other energy providers. Witness Maness stated that it would be inappropriate to require ratepayers to support advertising which included the promotion of electricity over gas, and that he did not think this Commission should send a message to utilities that ratepayers would finance a competitive war between electric and gas companies. Witness Maness further stated that he was

unaware of this Commission taking a position on the preference of either gas or electricity. Witness Maness testified that he had allowed advertising costs associated with ads that promoted the more efficient use of electricity but did not allow ads that promoted the use of electricity over gas.

The Company took the position that the purpose of this type of advertising was to promote energy efficiency and provide information to the Company's customers. On cross-examination, witness Chamberlain acknowledged that the Company is in competition for winter heating with gas companies and that the issue is the energy choice one makes. Furthermore, witness Chamberlain stated that he was unaware that the Commission had disallowed competitive advertising costs in North Carolina Natural Gas Corporation's last general rate case.

The Commission has carefully reviewed Public Staff Chamberlain Rebuttal Cross-Examination Exhibit No. 1 in regard to the competitive advertising costs in question. The Commission agrees with the Public Staff that it is proper to remove from operating revenue deductions advertising that is designed to compete with natural gas companies or with other energy providers. On the other hand, it is also proper to include in the cost of service advertising that is devoted to conservation, reduction of peak demand, and energy efficiency, all of which are permissible under Rules R12-12 and R12-13. Based on its review of the ads, the Commission finds and concludes that as many as one-half of the ads disallowed by the Public Staff for competitive advertising costs do indeed promote conservation, reduction of peak demand, and energy efficiency. Therefore, $54,000 of the Public Staff's recommended disallowance should be included in the Company's operating revenue deductions for purposes of this proceeding.

Witness Maness removed $11,000 of promotional advertising cost. Witness Maness testified that the promo-

tional advertisements were intended to promote the sale of outdoor or night lighting and as such the costs of the ads are not a legitimate cost of providing electric service to ratepayers. Witness Chamberlain took the position that this type of advertising promotes the use of efficient residential outdoor lighting. On cross-examination, witness Chamberlain stated that he was not familiar with the Commission Rules R12-12 and R12-13 which define promotional advertising. Furthermore, witness Chamberlain acknowledged that the "promotional" ads did not provide information to customers about converting from inefficient incandescent bulbs to high efficiency bulbs nor about using motion-sensor lighting that might be less wasteful. Witness Chamberlain also testified that the National Night Out Campaign advertisements were part of the Company's public service or community activities concerning crime prevention.

Based on the foregoing and its review of the advertisements in question, the Commission concludes that the Public Staff adjustment to exclude promotional advertising costs is appropriate. The Commission finds that the Company's promotional advertising is inconsistent with the provisions setting forth the allowable types of advertising in Commission Rules R12-12 and R12-13.

The remaining difference in advertising costs relates to the Public Staff exclusion of $13,000 of image advertising costs. Witness Maness testified that it was the Public Staff's position that image advertising was not a necessary cost for public utilities and therefore those costs should be removed from operating revenue deductions.

Witness Chamberlain testified that the ads that were classified by the Public Staff as image advertising were part of an overall ad campaign to provide information and meet customer needs. When questioned about various ads, such as the sweater recycling ads, witness Chamberlain admitted that the majority of the ads did not

directly address issues of safety or energy efficiency. On cross-examination concerning advertising for the Energy-share program, witness Chamberlain stated that this program was not image advertising but it was advertising consistent with the overall strategy of promoting Company name recognition.

Witness Chamberlain's position throughout his testimony was essentially that each ad was part of the campaign, and if the campaign was valid, then each part was also necessary. How NC Power reacts to its advertising agency's recommendations and how this Commission deals with the advertising costs are two entirely separate issues. The Commission will review each ad pursuant to its Rules.

After a careful review of Public Staff Chamberlain Rebuttal Cross-Examination Exhibit Nos. 1 and 2, the Commission concludes that the Public Staff adjustment is proper and consistent with the Commission's policy concerning image advertising. The Commission finds that the amount of image advertising costs to be removed from the cost of service is $13,000.

The second adjustment to operation and maintenance expense made by the Public Staff is the adjustment recommended by Public Staff witness Powell to the cost of capacity purchased from the Hadson project. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 34-59, the Commission has found this adjustment to be appropriate. Therefore, the Commission concludes that it is appropriate to reduce operation and maintenance expense by $1,390,000 to reflect the removal of unreasonable purchased capacity costs.

The next adjustment made by the Public Staff concerns officers' salaries. Public Staff witness Maness testified that consistent with the adjustments made by the Commission in recent years for other electric utilities, he was recommending an adjustment to charge the stock-

holder 50% of the compensation paid by the Company to those officers whose functions are most closely linked with meeting the demands of the Company's sole common stockholder, Dominion Resources, Inc. Witness Maness indicated that the officers whose compensation he split were as follows:

(1) President/Chief Executive Officer

(2) Chairman of the Board of Directors

(3) President/Chief Executive Officer of Dominion Resources, Inc.

Witness Maness testified that these three individuals are closely linked to meeting the demands of the Company's common shareholder. All three individuals serve on the Vepco Board of Directors, as well as the Dominion Resources, Inc. Board of Directors. The Chairman of the Vepco Board is also Chairman of the Dominion Resources, Inc. Board, as well as of the Boards of Dominion Resources, Inc.'s other subsidiaries, Dominion Capital, Dominion Energy, and Dominion Lands. Witness Maness testified that this adjustment is especially appropriate for Vepco given the nature of Dominion Resources, Inc.'s non-regulated business interests. Witness Maness stated that the interests of Dominion Resources, Inc. as they relate to its non-regulated businesses may not always coincide with the interests of Vepco's retail ratepayers. Witness Maness also testified that the Commission has adopted an adjustment consistent with his approach in each of the seven Duke, CP&L, and Vepco general rate cases decided since November 1984.

Company witness Schools testified that officers' compensation is an appropriate determinant of the cost of service. Witness Schools also testified that the allocation of officers' compensation between Vepco and other subsidaries of Dominion Resources, Inc. (which, according to the testimony of witness Maness, contributed to an increase of 96% in the compensation paid by Vepco to

the officers in question in this proceeding over and above that reflected in the last general rate case proceeding) is based on an Order of the Virginia State Corporation Commission. However, witness Maness pointed out that his adjustment focuses on the level of executive compensation paid by Vepco and testified that the fact that this compensation results from an allocation should not affect the evaluation of whether or not 50% of it should be assigned to the common stockholder. Witness Maness indicated that the adjustment is based on the duties that these officers perform as employees of Vepco, not as officers and employees of Dominion Resources, Inc.

After careful consideration, the Commission concludes that the Public Staff adjustment to exclude 50% of the compensation of the three officers in question is appropriate. The Commission finds that it is reasonable for the Company's common stockholder to bear 50% of the compensation expense of the Company officers whose function is most closely linked with meeting the demands of the stockholder. The Commission notes that this adjustment is consistent with adjustments made in the following 11 electric general rate cases:

> Duke Power Company—Docket No. E-7, Subs 338, 391, 408, and 487; Carolina Power & Light Company—Docket No. E-2, Subs 444, 461, 481, 526, and 537; and, NC Power—Docket No. E-22, Subs 265 and 314.

As it did in the Company's last general rate case, the Commission rejects any contention that this adjustment is inappropriate because some or all of the compensation in question results from an allocation process between the Company, its parent, and/or the parent's other subsidiaries. It is readily apparent that the compensation allocated to Vepco is at an executive level. Consequently, for purposes of evaluating the ratemaking treatment of their Vepco compensation, these individuals

should be treated as officers of Vepco. That they may also receive compensation from the parent company or its other subsidiaries on the basis of activities performed as employees of those entities is irrelevant to the question of whether a portion of their Vepco compensation should be assigned to the common stockholder on the basis of the inherent relationship between stockholders and the top executives of a utility. The Commission is making its adjustment on the basis of the relationship of Dominion Resources, Inc. to Vepco as a stockholder, not on the basis of the relationship of Dominion Resources, Inc. to Vepco as a co-employer of certain individuals. These two relationships are distinct and separate.

The next adjustment to operation and maintenance expense made by the Public Staff is its removal of the cost of community and governmental affairs projects. Public Staff witness Maness testified that these expenses fall in the category of contributions, donations, and other non-utility related items which are not a necessary cost of providing utility service. The Commission agrees that non-utility related items should not be included in cost of service and, consistent with its findings and conclusions regarding charitable contributions discussed elsewhere in this Order, concludes that the Public Staff adjustment to remove $10,000 related to community and government affairs projects from operation and maintenance expense is reasonable and appropriate.

The final Public Staff adjustment to operation and maintenance expense concerns the appropriate treatment of common stock issuance costs. As discussed in the Evidence and Conclusions for Finding of Fact No. 80, the Commission has found the adjustment recommended by Public Staff witness Hinton to be appropriate. Therefore, the Commisison concludes that the Public Staff adjustment to increase operation and maintenance expense by $41,000 to reflect common stock issuance costs is reasonable and appropriate for purposes of this proceeding.

In summary, the Commisison concludes that the level of operation and maintenance expense (other than fuel) under present rates appropriate for use in this proceeding is $75,065,000.

Depreciation and Amortization

The second area of difference between the Company and the Public Staff is depreciation and amortization expense. The difference consists entirely of the Public Staff adjustment to remove the North Anna Unit 3 amortization expense of $1,306,000 (as proposed by the Company) from expense. Public Staff witness Maness testified that because the amortization period established by the Commission for the North Anna Unit 3 abandonment loss will end approximately six months after the date rates become effective in this proceeding, inclusion of the remaining amortization expense in rates would result in a non-representative level of operating revenue deductions. Therefore, witness Maness removed the amortization from expenses. According to witness Maness, his recommended treatment is consistent with the treatment accorded the North Anna Unit 4 amortization by the Commission in the Company's last general rate case, Docket No. E-22, Sub 314.

However, witness Maness testified that it is reasonable in his view to provide the Company an opportunity to recover the remaining unamortized balance by another means. Therefore, he has recommended the establishment of a rider to recover this balance. This rider, based on the remaining unamortized balance of the loss, would expire one year after the date it becomes effective.

Company witness Schools testified that while the Company does not dispute the level of expenses used by witness Maness to calculate the rider, the use of such a rider is not warranted in this case. Witness Schools stated that the collection of North Anna Unit 3 costs throughout the

amortization period has been through base rates, and that the final amortization is a proper component of cost of service which should be collected through base rates, not unnecessarily singled out for separate treatment. Witness Schools also testified that the Company is not aware that the Commission has routinely employed the use of riders for purposes of segregating cost recovery in base rates.

Therefore, the Commission is presented with four options regarding this cost: include the remaining amortization in the cost of service, exclude it entirely from rates, amortize it over a longer period of time, or allow recovery through a rider. The Commission concludes that complete exclusion is not fair to the Company, just as inclusion in ongoing operating revenue deductions would not be fair to ratepayers. Amortization over a longer period of time would provide recovery for the Company, but the Commission does not want to extend the amortization period beyond the ten years ordered if it can be reasonably avoided. Recovery of the remaining cost through a one-year rider provides recovery of the cost and does not necessitate a significant extension of the amortization period. The Commission thus finds that approach to be the most appropriate of the four possibilities. A rider of shorter duration which would terminate exactly at the end of the ten-year amortization period would also achieve the Commission's objectives. However, the Commission believes that a twelve-month rider is a reasonable choice in that it mitigates the immediate increase in the revenue requirement imposed upon the ratepayer relative to a shorter rider and does not significantly extend the recovery period beyond ten years.

Consistent with its decision in Docket No. E-22, Sub 314, regarding the North Anna Unit 4 amortization, the Commission concludes that the remaining partial year's amortization of the North Anna Unit 3 loss should be removed from ongoing operating revenue deductions and

that recovery of the remaining loss should be accomplished through use of a one-year increment rider. The circumstances presented by this rate case are the same as those presented in Docket No. E-22, Sub 314 with regard to the North Anna Unit 4 amortization, in that it is known that the amortization period for the North Anna Unit 3 loss will end very shortly after the rates set in this proceeding go into effect. To set rates which are fair and reasonable, the Commission must strive to determine a representative level of operating revenue deductions. Because the amortization of North Anna Unit 3 ends so soon after the effective date of the rates established in this case, inclusion of the remaining cost in operating revenue deductions would clearly result in a non-representative level of operating revenue deductions.

During the hearing, the Company attempted to differentiate the North Anna Unit 3 treatment proposed by the Public Staff from the treatment accorded the North Anna Unit 4 amortization by the Commission in the Company's last general rate case, noting that the remaining North Anna Unit 4 loss was collected as an offset to a refund of excess deferred taxes (resulting in a net credit) and that the recovery was accomplished through a one-time lump-sum billing. The Commission concludes that the factors set forth by the Company do not substantively differentiate the two treatments. In both cases, the remaining partial year's amortization has been removed from ongoing operating revenue deductions and set for recovery through a special revenue mechanism. That the North Anna Unit 3 recovery is being effected over 12 months rather than one month, as was approved for North Anna Unit 4, amounts to only a matter of timing (i.e. a 12-bill rider rather than a one-bill rider). Likewise, the fact that there is no unrelated credit in this case against which to offset the recovery of the amortization is irrelevant to the question of the appropriate treatment to be given to the amortization. The combination of the

excess deferred tax refund with the North Anna Unit 4 loss in the last general rate case was simply a matter of convenience. The two issues themselves were completely unrelated to each other.

Therefore, the Commission concludes that it is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 3 loss amortization of $1,306,000 from depreciation and amortization expense. Consequently, the level of depreciation and amortization expense appropriate for use in this proceeding is $20,606,000.

The Commission also concludes that it is appropriate and reasonable to establish an increment rider in the amount of 0.066328¢/kWh, to expire one year from the date of this Order, for the purpose of allowing the Company to recover the remaining unamortized North Anna Unit 3 abandonment loss.

Income Taxes

The third area of difference between the Company and the Public Staff is income taxes. The difference of $881,000 is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to North Carolina state income tax surcharge rate	$ (4)
Adjustments related to Public Staff adjustments in other areas	885
Total	$881

The first Public Staff adjustment is its adjustment to the surcharge rate to be applied to North Carolina state income taxes. Public Staff witness Maness testified that he utilized a surcharge rate of 1.5%, the average of the rates for 1993 (2%) and 1994 (1%), as opposed to the

1993 rate of 2% utilized by the Company. In his opinion, use of the average rate is appropriate because the Company does not generally file a rate case annually.

Company witness Schools testified that it is uncertain at this time whether or not the Company will file a rate case in 1993. Witness Schools characterized the Public Staff adjustment as speculative and asserted that it builds into rates an undercollection of the 1993 level of expense. According to witness Schools, the 2% rate, being known and measurable, more accurately reflects the going level in this case.

Company witness Rhodes testified that assuming a reasonable result from this case and barring unforeseen circumstances, it is unlikely that the Company would file another general rate case this year. Additionally, witness Rhodes testified that the Company's last general rate case Order was issued approximately two years ago and that the next to last general rate case occurred about seven years before that one. Witness Schools testified subsequently that the actual decision regarding whether or not to file a case this year has not yet been made and that all of the information necessary to make that decision was not yet available.

With regard to the definition of the "going level in this case," Witness Schools testified that it involved looking essentially at a one-year rate period.

During cross-examination, counsel for the Company asked Public Staff witness Maness whether the change in the rate to 1% in 1994 is a known and measurable change taking place prior to the close of the hearing. Witness Maness replied that the change is known and measurable but would not take place prior to the close of the hearing. Witness Maness compared his treatment of the surcharge to the treatment of rate case expense,

in which an estimated annual level of rate case expense is set based on an estimate of the period of time lapsing between rate cases. Additionally, witness Maness testified that the surcharge adjustment should be based on current law, under which the rate will change to 1% in 1994, and not on the basis of any hypothetical actions the legislature might or might not take.

Witness Maness was also asked if it would be possible to treat the surcharge similarly to his proposed treatment for the North Anna Unit 3 amortization and establish a rider to recover all or a portion of the cost. Witness Maness testified that it would be possible, but that he considered North Anna Unit 3 to be an "exception to the rule," while the surcharge is handled in a more traditional manner. Witness Maness listed three differences between North Anna Unit 3 and the surcharge: the Commission's rationale in developing a ten-year amortization period, the large size of the North Anna Unit 3 cost in relation to the surcharge, and the precedent established by the Commission in the Company's last general rate case.

The Commission concludes that the expense included in this case for the North Carolina state income tax surcharge should be based on an average rate of 1.5%. It is known and measurable under current law that the rate is set at 2% for 1993 and 1% for 1994. The Commission also concludes that utilization of an estimated two-year period between this case and the next general rate case is reasonable, especially given witness Rhodes' testimony and that seven years passed between the Commission's rate case Orders in Docket No. E-22, Sub 273, and in Docket No. E-22, Sub 314, and two years between the Orders in Docket No. E-22, Sub 314 and in this case. The Commission thus finds it appropriate to spread the surtax to be incurred under current law, based on the jurisdictional state income tax expense found reasonable in this case, over the estimated period of time between rate cases of two years. This metholology

is consistent with that adopted by the Commission in such recent general rate cases as North Carolina Natural Gas Corporation (Docket No. G-21, Sub 293) and Duke Power Company (Docket No. E-7, Sub 487).

With regard to the Company's contention that a rider similar to the North Anna Unit 3 rider could be established for the surcharge, the Commission concludes that such a rider is not appropriate for purposes of this proceeding. The Commission has explained elsewhere in this Order that it is appropriate to remove the North Anna Unit 3 amortization from operating revenue deductions and effect its recovery through a temporary rider to be fair to both the Company and the ratepayers. Due to the relatively small size of the surcharge, it is not necessary to remove it from operating revenue deductions to set fair and reasonable rates.

The remaining Public Staff adjustments to income tax expense result from the other Public Staff adjustments to expenses as well as its recommended capital structure, cost rates, and rate base.

The Commission thus concludes based on its findings on rate base, revenues expenses, capital structure, and cost rates that the level of income tax expense under present rates appropriate for use in this proceeding is $8,607,000.

Charitable Contributions

The final area of difference in operating revenue deductions between the Company and the Public Staff is charitable contributions. The difference consists solely of the Public Staff adjustment to remove the charitable contributions of $89,000 (net of tax) included by the Company in operating revenue deductions. Public Staff witness Maness testified that he removed those items specifically identified by the Company in its filing as charitable and educational donations. Witness Maness testified that contributions are not a necessary cost of

providing utility service and that ratepayers should not be required to pay for contributions to charities selected by the Company rather than the ratepayers. Additionally, witness Maness testified that even if the Company's donations are not inconsistent with the public interest, they should not be passed through to the ratepayers in the price of electricity. He stated that nonregulated businesses that make donations have much less control over the price of their goods and services than does the Company.

Company witness Schools testified that the Company continues to support the inclusion of contributions as appropriate costs of service. Witness Schools testified that contributions are necessary in terms of corporate involvement in the community and being a good corporate citizen.

Under cross-examination, witness Schools agreed that he would assume that there would be a fairly wide disparity in the charities to which different ratepayers would contribute. Witness Schools also agreed that a residential ratepayer in Elizabeth City would not have the option of buying electricity from another provider if he disagreed with a charity to which the Company contributes.

Witness Schools testified that if the Company refused to make charitable contributions, it could result in ill-will or additional costs resulting from the refusal to make a particular contribution in the past. Witness Maness testified that he believed the ratepayers are interested in the provision of quality service at a reasonable cost and that by providing that, the Company can do much to maintain the goodwill felt toward it by the ratepayers.

The Commission concludes that the Company's charitable contributions should not be included in the cost of service. It has been a long-standing policy of this Commission to exclude contributions from operating expenses.

Charitable contributions are not a necessary cost of providing electric service.

Therefore, the Commission concludes that the Public Staff adjustment to remove $89,000 of charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

Based upon the Commission's conclusions in this Order, the Commission finds that the level of operating revenue deductions under present rates, excluding fuel expense, appropriate for use in this proceeding is $115,757,000, calculated as follows:

(000's Omitted)

Item	Amount
Operation and maintenance expense	$ 75,065
Depreciation and amortization	20,606
Other taxes	11,100
Income taxes	8,607
Other interest expense	208
Interest on tax deficiencies	171
Total	$115,757

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 75 AND 76

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Carney and Public Staff witness Hinton.

The Company and Public Staff are in agreement with respect to the capital structure and cost rates for long-term debt and preferred stock for use in this proceeding.

Therefore, the Commission finds and concludes that the capital structure and the cost rates for long-term debt and preferred stock appropriate for use herein are as follows:

	Capitalization Ratio %	Cost Rate %
Long-term debt	45.227	8.024
Preferred stock	9.955	5.598
Common equity	44.818	—
Total	100.000	—

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77-82

The evidence for these findings of fact is found in the testimony and exhibits of Company witnesses Avera and Carney and Public Staff witness Hinton.

The Company and Public Staff were not in agreement on the proper investor return requirement for common equity. Company witness Avera recommended that the Commission find 12.0% to 13.0% as the proper range for the cost of equity to the Company excluding any flotation costs. Public Staff witness Hinton recommended that the Commission adopt 11.5% as the cost of common equity for the Company in this proceeding.

In his pre-filed testimony, Company witness Avera employed three different methods in his cost of equity analysis: the constant growth DCF model, the non-constant growth DCF model, and the risk premium method.

In applying the constant growth DCF model, witness Avera studied 19 companies which he believed were comparable in risk to Dominion Resources, Inc., the parent holding company of Vepco. Using the constant growth DCF model, witness Avera determined that the investor return requirement was in the range of 8.9% to 12.22% for Dominion Resources, Inc. and 9.0% to 10.0% for the comparable group. Employing the non-constant growth DCF model, witness Avera estimated that the

cost of equity for Dominion Resources, Inc. ranges from 6.82% to 12.69% and the cost of equity for the comparable group ranges from 8.38% to 12.46%. However, because in witness Avera's judgment the DCF method was producing illogical and unreliable results which violated the risk/return tradeoff, he testified that the results of these models could not always be relied on as a measure of investor's required rate of return.

In conducting his risk premium analysis, witness Avera surveyed the literature and selected published studies which applied seven different analytical approaches. These approaches in general can be categorized as "mechanistic" DCF-derived comparisons, investor surveys, and historical earned returns comparisons. The various studies produced cost of common equity ranges of 11.60% to 15.37% and an average risk premium result of 13.57%.

Witness Avera testified that in his opinion 25 basis points should be added to the "barebones" cost of equity to adjust for flotation costs necessarily incurred when issuing common stock. His final recommendation to the Commission was a range of equity cost rates from 12.25% to 13.25% including this adjustment.

Public Staff witness Hinton employed two different cost of equity methods in his analysis of the investor return requirement for the Company. The first method witness Hinton employed was the constant growth DCF model. He performed a DCF analysis on Dominion Resources, Inc. and on two groups of utilities comparable in risk to Dominion Resources, Inc.—an electric utilities group and a non-electric utilities group. At the hearing, witness Hinton updated his DCF results. However, his conclusion for the cost of equity based upon the DCF results remained at 11.0% to 11.5%.

Witness Hinton also performed a risk premium study based upon a study performed at the Federal Energy Reg-

ulatory Commission (FERC). In his testimony he pointed out the advantages of the FERC approach and noted several criticisms of conventional applications of the risk premium method such as the use of historical data on earned returns dating back to 1926, the use of study results based solely on polling utility stock analysts, and reliance on risk premium studies which themselves display inconclusive and wide ranging results. Witness Hinton's risk premium study, which he updated at the hearing, indicated the Company's cost of equity to be in the range of 11.3% to 12.0%.

Witness Hinton testified that, in reaching his final cost of equity recommendation, he placed more emphasis on his DCF analysis than his risk premium analysis. He concluded that the current investor return requirement to the Company was in the range of 11.0% to 12.0% and recommended that the Commission adopt 11.50% as the investor required return on equity for the Company. Witness Hinton testified that, without evidence of any test year flotation costs associated with a public offering of its common stock and with no evidence of immediate plans of the Company to make such an offering, he could not recommend an adjustment to the return on equity for flotation costs. However, in view of the actual test year expenses associated with the Company's employee and customer stock purchase plans, which were provided by the Company, witness Hinton recommended an adjustment to the cost of service to reflect this ongoing level of expense.

In his pre-filed testimony, witness Hinton also reviewed the testimony of Company witness Avera. Witness Hinton replicated witness Avera's correlation analysis and stated that he disagreed with witness Avera's conclusion that the DCF model has stopped producing logical and reliable results.

Witness Avera also filed rebuttal testimony in this proceeding. In his rebuttal testimony, he criticized wit-

ness Hinton's use of the constant growth DCF model. Witness Avera contended that the current depressed state of the U.S. economy warranted the use of a non-conventional long run growth rate of 5.8%, which produced cost of equity estimates of 12.2% and 12.5% for Dominion Resources, Inc. and his comparable group of electric utilities, respectively. Second, witness Avera sought to rebut witness Hinton's approach to adjustment of risk premiums for changes in interest rates. Witness Avera criticized the Public Staff for understanding the interest rate relationship and for what he said was an improper application of the risk premium method. Third, he criticized witness Hinton's failure to adjust his return recommendation for historical issuance costs. Witness Avera asserted that the true flotation cost adjustment was 25 basis points. Finally, he criticized witness Hinton's failure to account for purchase power commitments in his pre-tax coverage ratio calculations. He contended that if witness Hinton had accounted for the view financial ratings agencies have of purchased power debt equivalents, his return on equity would only produce interest coverage ratios sufficient to support a triple-B bond rating.

During cross-examination, Company witness Avera was questioned on the calculated return on equity derived from his version of the non-constant growth DCF model. Witness Avera maintained that he considered some of the results from the general form DCF to be patently unreasonable. Witness Avera also acknowledged that the results of his non-constant growth DCF varied over a wide range for both Dominion Resources, Inc. and for his comparable companies. Upon further cross-examination, witness Avera acknowledged that the Commission, on page 62 of its Final Order in Docket No. E-22, Sub 314, was correct in its characterization that "the results from the non-constant growth DCF are simply too volatile."

Witness Avera was also cross-examined extensively on his application of the risk premium method in this case.

In response, he testified that the risk premium method does not provide a precise return on equity result. He acknowledged the Order for the prior NC Power rate case in 1991, Docket No. E-22, Sub 314, and the Federal Communications Commission's Order in 1991 which accepted neither his risk premium methodology nor his empirical DCF correlation study.

During cross-examination, witness Avera acknowledged several apparent inconsistencies in and between the risk premium studies which he employed. He acknowledged that Brigham, Shone & Vinson concluded:

> Risk Premiums like interest rates and stock prices are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched to current interest rates.

The Brigham, Shone & Vinson study also reported finding a significantly positive correlation of interest rates and risk premiums in one period and a negative correlation in another period. Upon further cross-examination, witness Avera acknowledged the findings of another study by Carleton, Chambers and Lakonishok which concluded:

> Using two models, which assume alternative expectations as to the outcome of rate of return regulation, we are unable to find a significant relationship between risk premiums and interest rates.

In his pre-filed testimony, witness Avera cited a risk premium study conducted by Charles A. Benore of the investment advisory firm of Paine Webber, Mitchell Hutchins, Inc. Witness Avera reported this study determined that utility equity risk premiums averaged 4.24% over double-A utility debt costs. He agreed that the Benore study cited in his pre-filed testimony reported that the risk premium for an electric utility not involved in

nuclear construction was approximately 3.17% in 1984 and 2.65% in 1985. On rebuttal cross-examination, witness Avera recalculated the risk premium result of the Benore study with the equity risk premiums of utilities without nuclear construction from the 1984 and 1985 surveys which he reported only marginally reduced the 12 year average equity risk premium from 4.24% to 4.06%. He also acknowledged that Vepco is not currently in the process of building a nuclear power plant.

With respect to his flotation cost adjustment of 25 basis points, witness Avera stated that this adjustment was proper even though the Company has not incurred any flotation costs in seven years and does not plan to incur any flotation costs in the foreseeable future.

On rebuttal, Company witness Carney was extensively cross-examined regarding the reasonableness of witness Avera's 25 basis point flotation cost adjustment to reflect the ongoing level of carrying costs associated with unrecovered past common equity issuance expenses. Attorney General Avera Rebuttal Cross-Examination Exhibit No. 2 showed that a 25 basis point adjustment to the Company's return on equity would, on a system-wide basis, result in increased revenues of approximately $15.8 million to the Company. Witness Carney acknowledged that in the last NC Power rate case the Commission awarded a 0.02% increase in the cost of equity to recover a representative level of common equity flotation costs.

Public Staff witness Hinton was cross-examined extensively on the assumptions used in deriving the constant growth DCF model and its relationship to the non-constant growth DCF model. He stated that the difference in the two models was that the non-constant growth model required an estimate of the stock price at a particular point in time whereas the constant growth DCF required an estimate of the growth rate in dividends to infinity. Witness Hinton stated that it is very difficult to

predict a stock price at a certain point in the future due to the daily market changes and that this aspect of the non-constant growth model increases the method's difficulty and unreliability.

Witness Hinton also answered several questions concerning the risk premium method in general. He testified that the historical risk premium approach can be easily manipulated depending on the time period selected. Upon cross-examination, he responded that the risk premiums studies used by witness Avera demonstrated inconclusive results, especially in the manner in which risk premiums and interest rates are related. He pointed out that some studies report a positive relationship while others report a negative relationship. He further testified that an obvious bias exists when a study utilizes a poll of stock analysts who also perform roles in selling or issuing that very common stock.

Witness Hinton pointed out several distinct advantages of the FERC approach in calculating a risk premium result over other risk premium studies, including the contemporaneous comparison of debt cost and equity costs specific to each utility, the use of current risk premiums over historical risk premiums, and the ability to observe the actual data used. During cross-examination, witness Hinton was asked several questions regarding his use of the FERC risk premium study which compares a utility's authorized returns on equity with its bond cost. He testified that the intent of the study was to measure the additional rate of return investors require to invest in a given utility's equity over its bonds. He was also cross-examined on the bond cost calculation for the Company. He testified that the bond cost calculation was in accord with the FERC study and that, at the time he filed the testimony, the bond cost calculation for the Company was equal to the 8.6% yield on the A-rated bond index for November 1992, as reported in Moody's Bond survey.

Witness Hinton also stated that, in view of the inherent problems associated with any cost of equity method that is largely dependent on bond yields, he gave more emphasis to, and had more confidence in, his DCF results. He testified that today's economic environment differs significantly from prior years, and the lower current DCF results indicate that investors are requiring a lower equity return for utility investments.

The determination of the fair rate of return for the Company is of great importance and must be made with great care because the return allowed will have an immediate impact on the Company, its stockholders, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed, it must balance the interests of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4)

> . . . as will enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and its existing investors.

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b)

> . . . supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of

the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States.

State ex rel. Utilities Comm. v. *Duke Power Co.*, 285 N.C. 377, 388, 206 S.E. 2d 269, 276 (1974).

The Commission is mindful that its conclusion of the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. *State ex rel. Utilities Commission* v. *Public Staff*, 322 N.C. 689, 699, 370 S.E. 2d 567, 573 (1988). Based upon the evidence in the record, the Commission concludes:

(1) *The proper capital cost rates are 8.024% and 5.598% for long-term debt and preferred stock, respectively.* The Company and Public Staff agreed that these cost rates are proper to employ in conjunction with the Company's September 30, 1992, capital structure. The Commission agrees with the Public Staff and the Company that these cost rates are proper to employ for purposes of this proceeding.

(2) *Company witness Avera's version of the general form DCF model and risk premium method as applied in this case should be accorded only minimal weight for purposes of this proceeding.* The results calculated from the non-constant growth DCF model are simply too volatile. The Commission also notes that witness Avera testified that "the general form DCF should not be heavily relied on."

The risk premium method as applied by witness Avera in this case is too easily manipulated. Evidence in the record showed there was a specific risk premium difference between utilities with and without nuclear construction programs. His pre-filed testimony failed to consider this risk premium difference and the Commission is not convinced that his adjustment to reflect nuclear construction programs is adequate or proper. Witness Avera's historical

risk premium analysis also failed to consider that current economic conditions are vastly different from the economic conditions that prevailed from 1926 to 1987. The Commission also finds that minimal weight should be accorded to his risk premium results because the academic studies used to determine the relationship of interest rates and risk premiums are inconclusive.

Evidence was presented that other regulatory agencies have rejected the use of the risk premium studies cited by witness Avera as supporting his cost of equity recommendation. The Commission dealt with this issue in the February 14, 1991, Order in the last NC Power case, Docket No. E-22, Sub 314, and now reaches the same conclusion: that minimal weight should be given to witness Avera's general form DCF and his risk premium methods.

Witness Avera's pre-filed constant growth DCF conclusions ranged from 8.9% to 10.4% for Dominion Resources, Inc. and between 9.0% and 10.0% for his comparable group. He also filed rebuttal testimony that presented a revised constant growth DCF model that combined a long-term growth adjustment for the U.S. economy and a growth adjustment for the Company, which produced cost of equity estimates of 12.2% and 12.7%.

The Commission is not convinced that the current state of the economy warrants incorporating two growth factors in the constant growth DCF. Therefore, the Commission gives minimal weight to witness Avera's non-conventional DCF growth adjustment.

(3) *The constant growth DCF model and the FERC risk premium approach as employed by witness Hinton should be given the greatest weight for purposes of determining the cost of equity capital in this case.*

Public Staff witness Hinton employed the constant growth DCF model which produced a cost of equity recommendation in the range of 11.0% to 11.5%.

The Commission does not agree with witness Avera's assertion that a stock's earnings, dividends, and book value must grow in lock-step for the constant-growth DCF model to be valid and useful for ratemaking purposes. Although the estimation of the prospective growth for these rates is necessarily problematic and requires a certain amount of subjective judgment, it appears to the Commission that witness Avera's non-constant growth DCF model is far more subjective.

Public Staff witness Hinton also utilized the FERC risk premium approach, which produced cost of equity estimates for Dominion Resources, Inc. in the range of 11.3% to 12.0%, based on a risk premium range of 280 to 350 basis points. The Commission finds no reason to believe that the required risk premium for the Company is in the significantly higher range recommended by witness Avera. The Commission further notes that, based upon the last NC Power Order, the FERC risk premium result was 2.86%, which is within the risk premium range recommended by witness Hinton.

The Commission notes that the FERC approach focuses on investors' required returns on electric utility investment, as opposed to the conventional risk premimum methods that analyze earned returns during economic conditions not comparable with today. The Commission, for purposes of this proceeding, finds that the constant growth DCF model and the FERC risk premium approach produce consistent, reasonable, and reliable estimates of the cost of equity and that these methodologies should be given the greatest weight for purposes of determining the cost of equity in this proceeding.

(4) *The investor return requirement to the Company is 11.8%.* In reaching this conclusion, the Commission has placed the greatest weight on estimates of the cost of common equity derived by use of Mr. Hinton's constant growth DCF model and, in particular, the FERC risk premium approach. Based upon those studies, Public Staff witness Hinton testified that the current investor return requirement to the Company is in the range of 11% to 12%. We conclude that a rate of return on common equity of 11.8%, which is well within the range testified to by Public Staff witness Hinton, is reasonable and appropriate in this case. In deciding to authorize a rate of return of 11.8% on common equity, the Commission has placed slightly greater weight and emphasis on the FERC risk premium approach than the constant growth DCF results. Only minimal weight has been accorded the evidence relating to the risk premium methods and the non-constant growth DCF model contained in the Company's testimony. Based upon the entire evidence of record, the Commission finds and concludes that the proper common equity investor return requirement for purposes of this proceeding is 11.8%.

(5) *The adjustment to allow the Company to recover test year common equity issuance expenses associated with the Company's stock purchase plans, as recommended by Public Staff witness Hinton, is appropriate.* This adjustment will allow the Company to recover a reasonable and representative test year level of issuance expenses for common equity for reasons stated by witness Hinton. This inclusion of issuance expenses in the test-year cost of service reflects an ongoing level of expenses associated with the Company's employee and customer stock purchase plans.

The Commission rejects witness Avera's 25 basis point flotation cost adjustment to the cost of equity

and finds no support for witness Carney's testimony that the Company has never collected past flotation costs. The Commission finds witness Avera's 25 basis point recommendation to be excessive and without support in the evidence of record, a factor of particular importance in view of the Supreme Court's holding that such evidence is essential. *State ex rel. Utilities Commission* v. *Public Staff*, 331 N.C. 215, 415 S.E. 2d 354 (1992). The Commission finds that the Company has incurred a fairly constant level of common stock issuance expenses for over seven years and concludes that the recommendation by witness Hinton is reasonable and supported by evidence of record.

(6) *The overall fair rate of return which the Company should be allowed the opportunity to earn on its rate base is 9.48%.* Based upon the Commission's findings with respect to the proper capital structure and the appropriate cost rates for each component of capital reflected in the capital structure, the Commission finds and concludes that the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 9.48%.

The Commission has also considered the question of the treatment of purchase power agreements as debt and the consequent potential risk to the bond rating of the Company. The Commission notes that its role is not that of a rating agency and that it must consider factors other than those considered by these agencies. The question of the proper treatment of these agreements is by no means closed. The Commission believes that as experience is gained, the various rating agencies may reconsider their treatment of these agreements. The Commission concludes that for purposes of regulation, these agreements should not be considered debt equivalents and that the interest rate coverage resulting from our decision in this matter is adequate. In this regard the

Commission agrees with the decision of the California Public Utilities Commission in *re Application of Pacific Gas and Electric Company,* Decision No. 92-11-047, which contains an extensive analysis of this issue. The Commission also notes that in his December 20, 1991, letter, Thomas E. Capps, President and Chief Executive Officer of Dominion Resources, Inc., argues that the net financial risk to the Company has not been increased by its purchased power program and that a procedure for full and timely recovery through rates is in place and working well.

It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witness, to draw inferences from the facts, and to appraise conflicting evidence. *State ex rel. Utilities Commission* v. *Duke Power Company,* 305 N.C. 1, 287 S.E. 2d 786 (1982); *Commissioner of Insurance* v. *North Carolina Rate Bureau,* 300 N.C. 381, 269 S.E. 2d 547 (1980). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not *res judicata* in succeeding cases. *State ex rel. Utilities Commission* v. *Duke Power Company,* 285 N.C. 377, 395, 206 S.E. 2d 269, 281 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations that vary from case to case." *State ex rel. Utilities Commission* v. *Public Staff,* 322 N.C. 689, 697, 370 S.E. 2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented and its weight and credibility in each case.

The Commission cannot guarantee that NC Power will, in fact, achieve the levels of return on rate base and common equity found to be just and reasonable in this Order. Indeed, the Commission would not guarantee the authorized rate of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds and concludes that the rate of return approved in this Order will afford the Company a reasonable opportunity to earn a reasonable return for its stockholder while providing adequate and economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The Comission has previously discussed its findings and conclusions regarding the fair rate of return which the Company should be afforded an opportunity to earn.

The following schedules summarize the gross revenue (excluding fuel revenue) and the rate of return which the Company should have a reasonable opportunity to achieve based upon the Commission's decisions in this case. These schedules, illustrating the Company's gross revenue requirement (excluding fuel revenue), incorporate the findings and conclusions made by the Commission. As reflected in Schedule I, the Company should be authorized to increase its annual level of non-fuel revenue by $10,642,000 based upon the adjusted test year level of operations.

SCHEDULE I

NORTH CAROLINA POWER

North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF OPERATING INCOME [3]
Twelve Months Ended December 31, 1991
(000's Omitted)

	Present Rates	Approved Increase	Approved Rates
Operating revenue	$144,377	$10,642	$155,019
Operating revenue deductions:			
Operation & maintenance expense	75,065	30	75,095
Depreciation & amortization	20,606	—	20,606
Other taxes	11,100	342	11,442
Income taxes	8,607	4,038	12,645
Interest on customer deposits	208	—	208
Interest on tax deficiencies	171	—	171
Total operating revenue deductions	$115,757	$ 4,410	$120,167
Net operating income	$ 28,620	$ 6,232	$ 34,852

[3] As noted elsewhere herein, this schedule does not reflect fuel revenues and associated-fuel expenses. Based upon the test-year level of operations, the proper level of fuel revenue and fuel-related expenses for use herein, after giving effect to the Commission's approved increase, is $30,007,000 (including gross receipts tax).

SCHEDULE II

NORTH CAROLINA POWER

North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Amount
Investment in electric plant:	
Electric plant in service including nuclear fuel	$598,046
Accumulated depreciation	(166,889)
Accumulated amortization of nuclear fuel	(36,842)
Accumulated deferred income taxes	(37,101)
Net investment in electric plant	357,214
Allowance for working capital:	
Materials and supplies	13,090
Cash working capital	(2,458)
Total allowance for working capital	10,632
Other cost-free capital	(15)
Rate base	$367,831
Rates of Return:	
Present rates	7.78%
Approved rates	9.48%

SCHEDULE III

NORTH CAROLINA POWER

North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
	Present Rates—Original Cost Rate Base			
Long-term debt	45.227%	$166,359	8.024%	$13,349
Preferred stock	9.955%	36,618	5.598%	2,050
Common equity	44.818%	164,854	8.020%	13,221
Total	100.000%	$367,831	—	$28,620
	Approved Rates—Original Cost Rate Base			
Long-term debt	45.227%	$166,359	8.024%	$13,349
Preferred stock	9.955%	36,618	5.598%	2,050
Common equity	44.818%	164,854	11.800%	19,453
Total	100.000%	$367,831	—	$34,852

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 84

Company witness Evans recommended that the basic revenue increase should be spread among the individual customer classes in such a way that the individual class rates of return move toward plus or minus 10% of the overall jurisdictional rate of return. He recommended that the Small General Service (SGS) class and the Outdoor Lighting Service (LITE) class be increased at the overall rate of increase. He recommended that the Residential Service (RES) class be increased approximately 1.2 times the overall rate of increase in order to move its low rate of return up closer to the overall rate of return. He also recommended that the Large General Service

(LGS) class and the Traffic Lighting Service (Traffic) class receive the remaining revenue increase in order to move their high rates of return down closer to the overall rate of return. The Commission estimates that the resulting increase for the LGS class and the Traffic class would be less than 0.8 times the overall rate of return.

Public Staff witness Turner recommended that the RES class should be increased approximately 1.07 times the overall rate of increase; that the SGS class should be increased approximately 0.9 times the overall rate of increase; that the LGS class should be increased approximately 0.98 times the overall rate of increase; that the LITE class should be increased approximately 0.53 times the overall rate of increase; and that the Traffic class should be increased approximately 0.92 times the overall rate of increase. The Public Staff presented a schedule of rate increases and rates of return based on the SWPA cost allocation method which indicated that its proposed rate of increase for each class would produce a rate of return for each class that is closer to the overall rate of return.

CIGFUR witness Phillips recomemnded that the maximum increase allowed by the Commission for the LGS class should be the rate of increase proposed for the LGS class by NC Power even if the SWPA cost allocation method is adopted. He also recommended that if the SWPA method is adopted, approximately $810,000 additional revenues should be shifted from the LGS class to the RES class in order to account for non-symmetrical treatment of fuel costs versus fixed costs in the allocation process.

CUCA recommended that the rates of increase for each customer class be sufficient to move the rates of return for each class at least one-third of the way toward equal rates of return, provided no class receives more than a 20% increase.

The Commission estimates that increasing the RES class by 1.125 times the overal rate of increase will move the RES class rate of return approximately one-fourth of the way toward equalized rates of return. The Commission also estimates that increasing the LGS class by 0.875 times the overall rate of increase will move the LGS class rate of return approximately one fourth of the way toward equalized rates of return. The estimates are based on rates of return produced by the SWPA allocation method.

The Commission concludes that the RES class should be increased 1.125 times the overall rate of increase, the LGS class should be increased 0.875 times the overall rate of increase, and the remaining classes should be increased 1.0 times the overall rate of increase. Such increases will produce rates of return for each rate class respectively that are within 10% plus or minus of the overall rate of return, and they will produce rates of return for each rate class respectively that are closer to equalized rates of return than they were before the increases.

The per books cost of service study (SWPA method) by NC Power indicated that the rate of return for the Traffic class was considerably higher than the overall rate of return, whereas the comparable study based on adjusted revenues and expenses presented by the Public Staff indicated that the rate of return for the Traffic class was approximately the same as the overall rate of return. The Traffic class is a new class established in this proceeding, and the total revenues and expenses attributable to the class are so small that the various accounting adjustments made in this proceeding could have a disproportionate impact on the cost of service study results for the Traffic class. Therefore, out of an abundance of caution, the Commission chooses to increase the Traffic class at 1.0 times the overall rate of increase.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 85

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness Turner. The Company proposed to increase the current residential summer/winter rate differential to 1.0¢/kWh from 0.51¢/kWh, and has based its proposal on the results of a study using forecasted summer and winter peak loads and the Company's capacity expansion model and long-range planning model. The Company's study supports a summer/winter rate differential of 1.9¢/kWh.

Public Staff witness Turner stated that pricing in North Carolina should be based on an embedded cost-of-service study and that North Carolina is required to base the revenue requirement on a historical test year. He contended that forecasted information is by definition not accurate, and he pointed out that the Company's study supporting the 1.9¢ summer/winter rate differential is based on forecasted summer and winter peaks and on future-looking econometric models. He recommended that the Commission hold the rate differential at its current level until the Company submits an embedded cost-of-service study that differentiates costs between the summer and non-summer periods. In addition, he recommended that any such study should also show seasonal cost differentials for both residential and nonresidential customer classes since the Company has summer/winter rate differentials for its non-residential rate schedules also.

Company witness Evans testified that the summer/winter rate differential had been an effective tool in controlling the residential and system summer peak loads and thereby reducing additional generation requirements. He stated that the summer/winter rate differential strategy is a significant reason why the gap between the Company's summer and winter peak loads is narrowing, and that the

narrowing gap results in a more efficient generation system with lower overall customer rates.

Witness Evans testified that he had no dispute with the Public Staff position that revenue requirements in North Carolina should be based on an embedded cost of service study for a historical test period. Nevertheless, he disagreed that individual rate structures should always reflect embedded cost characteristics. He indicated that projected future peak loads are critical from a resource planning perspective, and that such projected future loads should be reflected in the summer/winter rate differentials.

Witness Evans agreed that the Company should address the summer/winter rate differentials for non-residential customers as well as for residential customers. However, the Company elected to focus on the seasonal rate differential for the residential class of customers in this proceeding because it is the most weather sensitive class and presents the greatest opportunity to achieve load management objectives through seasonal pricing. He also testified that it is unlikely that an embedded cost study of seasonal differences in costs would support the proposed summer/winter differentials.

The Commission concludes that the 1.0¢/kWh summer/winter rate differential for residential customers should be approved. The differential seems to achieve generally accepted load management objectives, and it is based on a detailed study performed by the Company, although not an embedded cost study. The Commission anticipates that the Company will perform comparable studies of seasonal cost differentials for non-residential customers for presentation in future proceedings, and that such studies will be at least as detailed as the current ones.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 86

Public Staff witness Turner recommended moving the basic customer charge for residential service closer to actual cost, offset by a corresponding reduction in the energy charge for the service. The Company did not oppose his recommendation, and no other party addressed the proposal.

Witness Turner stated that the basic customer charge proposed by the Company is significantly below cost and should be increased in such a manner as to bring the charge closer to cost. The Company proposed to increase the basic customer charge to $8.50 per month from $7.16. Its cost-of-service study indicates the basic customer charge should be within a range of $15.40 to $15.60 per month based on the Company's proposed rates. Witness Turner recommended that the customer charge be increased to $9.50 per month.

Based on the Company's proposed rates, a typical residential customer with usage of 1,000 kWh per month will have an average percentage increase of 18.47% during the summer and 13.41% during the winter if the per month basic customer charge is raised to $9.50 as proposed by the Public Staff. In comparison, the percentage change for the typical customer based on the basic customer charge of $8.50 as proposed by the Company would be 18.52% and 13.5% during the summer and winter periods, respectively.

Based on the foregoing evidence, the Commission concludes that the residential basic customer charge should be increased to $9.50 per month.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 87-91

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans. Witness Evans testified that the embedded cost of distribu-

tion plant is approximately $916 per residential customer, and that the $916 per customer is reflected in current residential rates. However, the Company is currently investing approximately $2,103 per residential customer in new distribution plant for new residential customers, which results in approximately $1.8 million per year additional plant investment which must be absorbed by all residential customers, not just new customers.

Witness Evans testified that the proposed new line extension plan will require up-front payments for new residential services more frequently. The new plan will continue to require up-front payments for new non-residential services, and such up-front payments will also be more frequent. He estimated that the new plan will recover $1 million per year more from new residential customers and approximately $75,000 per year more from new non-residential customers.

Witness Evans testified that the proposed new line extension plan will continue to require up-front payments from new customers based on a revenue test, but that criteria for the revenue test would be revised in various ways in order to allow a more complete recovery of the investment required for new distribution plant. The more complete recovery of investment in new plant would help delay future general rate increases. He also indicated that the proposed new plan would have some influence over the choice of energy suppliers by prospective customers, but insisted that the plan was not designed to promote one energy source over another.

Witness Evans described the transition process from the current line extension plan to the proposed new plan, and indicated that the Company was requesting 90 days after approval of the plan before making the revisions effective in order to have time to inform its customers of the changes in the plan.

No party to the proceeding opposed the proposed new line extension plan. However, the Company stipulated

with the Public Staff during the hearing on revised language for the line extension plan that would permit a residential customer to request overhead construction rather than underground construction, and that would permit costs for the line extension being determined based on overhead construction costs rather than the more expensive underground construction costs. The Commission is aware that underground line extensions are currently the preferred method of construction for most new residential dwellings; however, overhead line extensions were recognized as the standard method of service connections for many years.

The Commission is of the opinion that the proposal by the Company to recognize underground construction costs coupled with a revenue test applied to these construction costs is an acceptable method of ensuring that the specific costs imposed by new customers on the system are compatible with the revenue contribution these customers are making to the system. Nevertheless, the Commission finds it appropriate for customers who so desire to continue to receive overhead line extensions, and for the construction costs applied in these instances to the corresponding revenue credit to be determined on a case-specific basis. This determination is consistent with the language agreed to by the Company and the Public Staff and introduced as evidence during the cross-examination of Company witness Evans in this proceeding.

The Commission concludes that the proposed new Line Extension Plan, as modified during the hearing, is appropriate and should be approved to become effective 90 days after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 92-95

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness McLawhorn.

Witness McLawhorn testified that the Company should upgrade the thermal standards used to qualify new residential customers for the Residential Conservation Reduction (RCR) so that the benefits derived over and above the requirements of the new North Carolina Building Code to be effective April 15, 1993, are similar to the benefits derived currently. Witness McLawhorn stated that without these changes, new customers would be receiving a rate discount for merely doing what is required by law. Company witness Evans agreed and indicated that the Company would be filing updated standards for Commission approval prior to the effective date of the new building code.

The Commission recognizes the benefits to be derived from DSM programs which ensure a greater level of energy efficiency; however, any incentives paid by the utility to its customers for participation in these programs should be commensurate with the level of benefits received. Therefore, the Commission is of the opinion that the RCR standards applied to new customers should be upgraded so that the benefits over the new building code requirements are maintained at a level comparable to the current benefits.

To this end, the Company should file revised standards before the April 15, 1993, effective date of the new code for Commission approval as agreed to by witness Evans. This filing should include a comparison of the current standards versus the current building code with the new revised standards versus the new building code, along with a quantification of the resulting benefits in each case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 96

The evidence for this finding of fact is found in the testimony of Company witness Evans and CIGFUR witness Phillips.

Witness Evans testified that since the introduction of Schedule 6C, the Company has implemented several provisions to assist the customer in participating in this program. For example, the Company has implemented a provision to allow one curtailment request per season to be excluded in determining compliance (i.e., one waiver per season); the time period from notification until the customer must reduce load has been extended from 10 minutes to 30 minutes; and the potential curtailment period in the summer was reduced from a 12-hour window to a 7-hour window, while in the winter, this window was reduced from 16 hours to one of two five-hour windows (or a total of 5 hours per day). He testified however, that for the Company to offer a cost-effective curtailable rate, the program must be designed with provisions that provide comparable value to a supply-side option. Often the peak hour in the winter occurs in the morning, but there is also need for load management in the late afternoon and early evening hours on extreme weather days. The curtailable rate must include both five-hour windows (for a total of 10 hours per day) if the rate is to be cost effective. A supply-side option such as a combustion turbine would be available to meet both the morning and afternoon peaks.

Witness Evans noted that if the Company elects to request a curtailment in both the morning and the afternoon of the same day, each curtailment will count as a separate request toward the maximum allowable 13 requests per winter season. Accordingly, he stated, this provision would not be overly burdensome to the customer, yet would provide the Company with the means to best manage its seasonal peaks and provide for a cost-effective demand-side program.

CIGFUR witness Phillips opposed the change and recommended that the Commission reject it. He stated that a customer should not be obligated to more than one curtailment per day, consistent with past practice. In his opinion, the proposal would be overly burdensome

and disruptive to customer operations and should not be allowed.

The Commission concludes that the proposed change is reasonable and should not be overly burdensome on customers. The Commission is mindful of the fact that these are voluntary rates, and that the Company has already made a number of modifications to the rates to resolve past difficulties. Therefore, the Commission concludes that the proposed modification to rate Schedule 6C, Schedule SG, and Schedule CS to allow the Company to request two curtailments per day during the winter season is appropriate and should be allowed.

The Commission is also of the opinion that the Company should file a report with the Commission approximately 12 months after the date of this Order describing the number of customers added and lost from the curtailable rates described herein since the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 97

In addition to the specific modifications discussed elsewhere herein, the Company proposes various miscellaneous rate changes, administrative changes and clarifications in its rate schedules which are unopposed by any party.

Highlights of such changes include the following:

(a) Add new rate schedule 5C for cotton gin service;

(b) Add new rate schedule 30T for traffic light service and delete traffic lights from municipal rate schedule 30;

(c) Add Christmas Eve as an off-peak holiday on all TOU rate schedules;

(d) Revise the definition of on-peak hours applicable to Power Supply Demand on TOU rate schedule 5P and 6P;

(e) Revise the SEER rating for heat pumps from 8.7 to 10.0 in order for multi-family or single family homes to qualify for the Residential Conservation Reduction; and

(f) Add provisions allowing installation of new mercury vapor lighting for government facilities.

The Commission concludes that the rate schedules proposed by the Company are reasonable and should be approved as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 98 AND 99

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness Turner. The Company proposed to change the conditions under which it will deliver electric service. Currently, the Company reserves the right to require the applicant to establish that he is the owner or bona fide lessee of the premises and to execute an application for service or the most current "Agreement for the Purchase of Electricty" on file with the Commission. The change proposed by the Company would require all owners and bona fide lessees to apply jointly for service. Witness Turner recommended that no change be made in the current requirement.

Witness Turner expressed the opinion that the proposal is an unduly cumbersome method of receiving applications for electric service and goes beyond usual conditions for service. He further stated that, while the purpose of the revision is to provide the Company with an additional resource in recovering unpaid bills, the Company did not support the proposal with documentation showing the magnitude of the problem nor does it state the conditions under which the Company would impose this requirement. As the language stands, it would be left as a discretionary decision of the Company. He

stated his opinion that the Company's present requirement for customer identification and a deposit is sufficient.

On cross-examination, witness Evans stated the Company would not contest the Public Staff's opposition and would withdraw the proposed change at this time. Based on the foregoing evidence, the Commission concludes that the changes proposed by the Company to paragraph II.A.1 of the Company's Terms and Conditions for the delivery of electric service rules and regulations should not be approved.

In addition to the specific modifications discussed elsewhere herein, the Company proposes various miscellaneous rate changes, administrative changes and clarifications in its terms and conditions of service which are unopposed by any party.

Highlights of such changes include revised service charges as follows:

Service connections	From	$23.74 to $20.55
Bad check charge	From	$12.71 to $14.47
Trouble call charge if customer's responsibility	From	$33.75 to $25.73
Reconnect charge during normal hours	From	$29.40 to $33.80
Reconnect charge after normal hours	From	$45.00 to $73.83

Other highlights include an increase in the minimum charge for additional meters for an individual customer from $0.97 to $18.25; and revision of the extra facilities charge in order to reflect the rate of return.

The Commission concludes that the terms and conditions of service proposed by the Company are reasonable and should be approved as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 100

The evidence supporting this finding of fact is contained in the record in this case. G.S. 62-133.2 provides that the Commission shall hold a hearing within 12 months after an electric utility's last general rate case Order to determine whether an increment or decrement rider is required ". . . to reflect actual changes in the cost of fuel and the fuel cost component of purchased power over or under base rates established in the last preceding general rate case." G.S. 62-133.2 further provides that additional hearings shall be held on an annual basis but only one hearing for each such utility may be held within 12 months of the last general rate case. G.S. 62-133.2(c) sets out the verified, annualized information and data which the utility is required to furnish to the Commission at the hearing for a historic 12-month period" . . . in such form and detail as the Commission may require . . ." Pursuant to Rule R8-55, the Commission has prescribed the 12-month period ending June 30, 1992, as the test period for the fuel proceeding.

The Company indicated in its July 31, 1992 Application for a General Increase in Rates (Docket No. E-22, Sub 333) that it intended to update its calculations of fuel cost in the general rate case for the 12-month period ended June 30, 1992, consistent with the Company's annual fuel clause test period. On September 30, 1992, NC Power filed a Motion for Consolidation of Hearings in which it moved to consolidate hearings in its general rate case and its fuel clause proceeding, Docket No. E-22, Subs 333 and 335, which motion was granted by the Commission in its October 5, 1992 Order. The Commission concludes that the appropriate test period for the base fuel factor determination is the 12-month period ending June 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 101-103

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witnesses Ross and Evans and Public Staff witness Lam.

Company witnesses Evans and Ross (Mr. Ross adopted the testimony of Daniel J. Green) and Public Staff witness Lam testified with regard to the July 1, 1991, to June 30, 1992, test period sales, test period generation, and normalized nuclear capacity factor. Company witnesses Ross and Evans testified that the July 1, 1991, to June 30, 1992, test period levels of sales and generation were 57,794,906 mWh and 61,448,089 mWh, respectively. The 57,794,906 mWh of test period sales reflects 57,825,522 mWh of actual sales as reported in Rule R8-55(d)(1), reduced by 30,616 mWh to reflect that Old Dominion Electric Cooperative sales are booked at production level. The test period per book system generation includes various energy generations as follows:

	mWh
Coal	25,992,366
Nuclear	22,978,300
Heavy Oil	1,912,993
Natural Gas	87,836
Internal Combustion	1,413,808
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,268,968
Other	5,234,861
Interruptible Sales	(2,551,212)

Public Staff witness Lam accepted the levels of sales and generation as proposed by the Company for use in his fuel computation.

Company witness Ross testified that the Company achieved a system nuclear capacity factor of 77.7% for

the July 1, 1991, to June 30, 1992, test period. Witness Ross normalized the system nuclear capacity factor to a level of 69.24%, which is the latest North American Electric Reliability Council's (NERC) five-year nuclear capacity factor. Witness Lam agreed that the nuclear capacity factor of 77.7% as achieved by the Company was abnormally high and should be normalized to the latest NERC five-year pressurized water reactor average of 69.24%. No other party offered testimony on the normalized nuclear capacity factor. In the absence of evidence presented to the contrary, the Commission concludes that the July 1, 1991, to June 30, 1992, test period levels of sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 69.24% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 104

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Ross and Green and Public Staff witness Lam.

Company witness Ross and Public Staff witness Lam testified regarding normalized generation. In Docket No. E-22, Sub 333 (rate case proceeding), witness Ross proposed a normalized generation using a historical level of generation based on 12 months ended December 31, 1991. In Docket No. E-22, Sub 335 (fuel clause proceeding), witness Ross proposed a normalized generation based on the 12-month test period ended June 30, 1992. The Public Staff accepted the Company's proposed normalized generation based on the 12-month test period ended June 30, 1992, as being appropriate for use in determining the fuel factor.

The Commission concludes that normalized generation should be based on the 12-month test period ended June 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 105

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

Witness Evans testified that consistent with Commission Rule R8-55(d)(2) the Company's system sales data for the 12-month period ending June 30, 1992, was adjusted by jurisdiction for weather normalization, customer growth, and increased usage. Witness Evans adjusted total Company retail sales by 818,572 mWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 280,695 mWh, 183,088 mWh and 354,789 mWh, respectively. The Public Staff reviewed and accepted these adjustments.

Based on the foregoing evidence, the Commission concludes that the adjustments due to customer growth, increased usage, and weather normalization of 280,695 mWh, 183,088 mWh, and 354,789 mWh, respectively, are reasonable and appropriate adjustments for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 106

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Ross and Evans and Public Staff witness Lam.

Company witness Evans and Public Staff witness Lam addressed the adjusted level of generation. Witness Evans presented an adjustment to per book mWh generation for the 12-month period ended June 30, 1992, due to

weather normalization, customer growth, and increased usage of 861,066 mWh, to arrive at witness Ross's adjusted generation level of 62,309,169 mWh.

The Public Staff accepted witness Evans' adjustment to per book mWh generation for the 12-month period ended June 30, 1992, due to weather normalization, customer growth, and increased usage. Witness Lam accepted witness Ross's generation level of 62,309,169 mWh which includes various energy generations as follows:

	mWh
Coal	28,130,404
Nuclear	20,474,196
Heavy Oil	2,070,346
Natural Gas	95,061
Internal Combustion	1,530,090
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,784,633
Other	5,665,469
Interruptible Sales	(2,551,212)

Based on the foregoing evidence and with no other evidence to the contrary, the Commission concludes that the adjustment of 861,066 mWh is reasonable and appropriate for use in this proceeding, and that the resultant adjusted fuel generation level of 62,309,169 mWh is also reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 107-109

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Ross and Public Staff witness Lam.

Witness Green's prefiled testimony of September 11, 1992, which was adopted by witness Ross, contained fuel

prices as follows: (1) coal price of $14.27/mWh; (2) nuclear fuel price of $4.69/mWh; (3) heavy oil price of $24.90/mWh; (4) natural gas price of $30.59/mWh; (5) internal combustion turbine price of $18.50/mWh; (6) other purchased and interchanged power price of $17.23/mWh; and (7) hydro, pumped storage, and non-utility generation at a zero fuel price.

Witness Lam, in his testimony, accepted witness Ross's fuel prices for heavy oil ($24.90/mWh), natural gas ($30.59/mWh), and hydro, pumped storage, and NUG generation (zero fuel price) and total fuel cost of interruptible sales of $28,446,000. However, witness Lam updated the fuel prices for the other types of generation to September 1992 fuel prices. Heavy oil and natural gas prices were not updated because there was none or very little generation using these two fuels in September. Witness Lam recommended updated fuel prices as follows: (1) coal price of $14.26/mWh; (2) nuclear price of $4.59/mWh; (3) internal combustion turbine of $21.33/mWh; and (4) other purchased and interchanged power price of $15.12/mWh.

Witness Ross and witness Evans, on rebuttal, accepted all of the fuel prices recommended by witness Lam. In the absence of any evidence to the contrary, the Commission concludes that the Company fuel prices accepted by the Public Staff and fuel prices recommended by the Public Staff and accepted by the Company are reasonable and appropriate for use in this proceeding.

Accordingly, the fuel calculation incorporating these conclusions is shown in the following table:

	Adjusted Generation (mWh)	Fuel Price $/mWh	Fuel Dollars (000's)
Coal	28,130,404	14.26	$401,140
Nuclear	20,474,196	4.59	93,977
Heavy Oil	2,070,346	24.90	51,552
Natural Gas	95,061	30.59	2,908
Internal Combustion	1,530,090	21.33	32,637
Hydro	2,302,348		
Pumped Storage	(2,192,202)		
Purchase & Interchange			
NUG	6,784,633		
Other	5,665,469	15.12	85,662
Interruptible Sales	(2,551,212)		(28,446)
System mWh Sales & Total Fuel Cost	58,613,478		$639,430
Base Fuel Factor			1.091¢/kWh

The Commission concludes that adjusted fuel test period expenses of $639,430,000 and the base fuel factor of 1.091¢/kWh, excluding gross receipts tax (1.127¢/kWh with gross receipts tax), is reasonable and appropriate for use in this proceeding. No party opposed this calculation. This approved base fuel factor is 0.078¢/kWh lower than the current level in effect of 1.205¢/kWh, including gross receipts tax (this consists of the current base fuel factor of 1.204¢/kWh and the current fuel adjustment increment from the fuel adjustment proceeding in Docket No. E-22, Sub 329, of 0.001¢/kWh, all including gross receipts tax). Such change will result in a decrease in fuel revenues of $2,076,777 based upon the adjusted level of sales of 2,662,535 mWh for the test year through the update period ending September 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 110-112

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

North Carolina General Statute 62-133.2(d) requires the Commission to "incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." Further, Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Company witness Evans testified that the Company overcollected its fuel expense by $1,308,510 during the test year ending June 30, 1992. He calculated interest for this overcollection of $218,085 in accordance with Rule R8-55(c)(5) using a Commission approved 10% interest rate. Further, witness Evans testified that the adjusted North Carolina jurisdictional fuel clause test year sales are 2,629,412 mWh. Public Staff witness Lam testified that he reviewed the Company's calculations of the fuel expense overcollection, the interest for this overcollection, and the North Carolina jurisdictional sales and agreed with the results.

The Company is proposing to refund the fuel revenue overcollection and associated interest to the customers over a 12-month period beginning March 1, 1993, using the adjusted North Carolina retail sales of 2,629,412 mWh as determined by the Company and accepted by the Public Staff.

The Commission concludes that the Company's calculation of the fuel revenue overcollection and associated

interest of $1,308,510 and $218,085, respectively, are appropriate for use in this proceeding and should be refunded to the customers over a 12-month period. No party opposed these calculations. This refund should be in the form of a separate EMF rider.

The $1,308,510 overcollected fuel revenue plus the $218,085 of interest was divided by the adjusted North Carolina jurisdictional sales of 2,629,412 mWh to arrive at the Company's proposed EMF decrement of 0.058¢/kWh, excluding gross receipts tax (0.060¢/kWh including gross receipts tax). Public Staff witness Lam accepted this proposed EMF decrement. The Commission concludes that there being no controversy, the proposed EMF decrement of 0.058¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding, and shall become effective on the date of this Order and shall expire one year from that date.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 113

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

Based upon our prior findings in this proceeding the Commission finds that the final fuel factor approved for usage in this case is 1.033¢/kWh. This final fuel factor consists of a base fuel factor of 1.019¢/kWh and an EMF decrement rider, including interest, of 0.058¢/kWh, all excluding gross receipts tax.

IT IS, THEREFORE, ORDERED as follows:

1. That NC Power is authorized to adjust its electric rates and charges effective for service rendered on and after the date of this Order to produce an increase in gross annual revenue, excluding fuel revenue, from its North Carolina retail operations of $10,642,000 based upon the adjusted test year level of operations.

2. That the Company shall replace the current base fuel factor of 1.204¢/kWh, including gross receipts tax, approved in general rate case Docket No. E-22, Sub 314, with the new base fuel factor of 1.127¢/kWh, including gross receipts tax, approved in this proceeding. The Company shall also refund over-recovered fuel expense and interest in the form of a separate rider (an EMF decrement of 0.060¢/kWh including gross receipts tax). This rider shall become effective on the date of this Order and shall expire one year from that date.

3. That the Company is authorized to place in effect an increment rider of 0.066328¢/kWh to recover the remaining unamortized balance of the North Anna Unit 3 abandonment loss. This rider shall become effective on the date of this Order and shall expire one year from that date.

4. That within five (5) working days after the date of this Order, the Company shall file with the Commission five copies of its rate schedules and service regulations designed to produce the increase in revenues adopted herein in accordance with the rate design guidelines attached hereto as Appendix A. The rate schedules required herein shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule.

5. That the Company shall prepare cost allocation studies for presentation with its next general rate case which allocate production plant based on the following methodologies: (a) Summer/Winter Peak and Average; (b) Summer/Winter Coincident Peak; (c) Average and Excess. The studies shall be included in Item 45 of Form E-1 of the minimum filing requirements for general rate applications.

6. That within 10 working days after the date of this Order, the Company shall file with the Commission 30 copies of computations showing the overall North Carolina retail rate of return and the rates of return for each

rate schedule which will be produced by the revenues approved by this Order. These computations shall be based on the cost allocation methodology approved by this Order.

7. That the Company shall give appropriate notice of the approved rate increase by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle following the filing and approval of the rate schedules described herein. The Company shall submit its proposed customer notice to the Commission for approval before it is mailed to the customers.

8. That the Company shall file new revised standards necessary to qualify for the Residential Conservation Reduction (RCR), which shall show that the relative benefit of the new revised standards to the new building code is substantially the same as the relative benefit of the current standards to the current building code as described herein. The new revised standards shall be filed with the Commission by April 15, 1993.

9. That the proposed new Line Extension Plan as described herein is hereby approved to become effective 90 days after the date of this Order.

10. That the Company shall make a study of the fuel costs and other costs incurred to serve the LGS customer class relative to the remainder of the system in accordance with the Commission's conclusions described herein. The results of the study and supporting workpapers shall be filed with the Commission and the Public Staff within 12 months after the date of this Order. The Company shall also file quarterly reports with the Commission regarding the progress of the studies as described herein.

11. That the company shall file a report with the Commission approximately 12 months after the date of this Order describing the number of customers added and lost from the curtailable rate schedules 6C, SG and CS since the date of this Order.

12. That the Company's proposed change to paragraph II. A.1 of its Terms and Conditions for the delivery of electric service rules and regulations is disapproved.

13. That the other proposed rate designs and modification and the other proposed changes in the Terms and Conditions are approved and may be implemented.

14. That the Public Staff shall investigate Vepco's NUG contracts for projects in commercial operation in conjunction with NC Power's next general rate case and present the results of such investigation as part of its testimony in that proceeding.

ISSUED BY ORDER OF THE COMMISSION

This the 26th day of February, 1993.

NORTH CAROLINA UTILITIES COMMISSION

/s/ Geneva S. Thigpen
GENEVA S. THIGPEN
Chief Clerk

[SEAL]

Commissioner Cobb dissenting in part.

APPENDIX A

NORTH CAROLINA POWER

DOCKET NO. E-22, SUB 333

Guidelines for Design of Rate Schedules

(A) Set the Basic Customer Charge for Residential Service at $9.50.

(B) Hold the extra charges and miscellaneous service charges at the same levels proposed by the Company.

(C) Distribute the overall revenue increase approved herein in accordance with the following rate of increase indices:

	Rate of Increase Index
Residential	1.125
Small General Service	1.000
Large General Service	0.875
Outdoor Lighting	1.000
Traffic Signals	1.000
Overall	1.000

(D) Maintain revenue neutrality between comparable time-of-use rate schedules and non-time-of-use rate schedules.

(E) Maintain the relative price levels proposed for each rate schedule consistent with the overall rates of increase approved herein, except as specifically revised herein.

DOCKET NO. E-22, SUBS 333 AND 335

COMMISSIONER COBB, DISSENTING, IN PART.

1. I dissent from Finding of Fact 59 which reduces the operation and maintenance expense by $1,390,000 to reflect alleged unreasonable purchase capacity costs in connection with the Hadson projects. While I agree that this Commission is not bound by the actions of the Virginia State Corporation Commission as a matter of law, I do not feel that the factual situation in this case justifies such disallowance. Neither do I agree with the majority concerning the standards to be met for disallowance.

The majority cites other cases involving the adjustment of fuel expenses to reflect abnormal weather conditions and other factors as justification for its conclusion that there need not be a finding of management imprudence to disallow expenses. These decisions are readily distinguishable in that failure to adjust clearly would have resulted in the substantial over recovery of expenses whereas the majority decision in this case will preclude the recovery of $1,390,000 in costs actually incurred.

In my opinion, North Carolina Power did everything a reasonable and prudent person would be expected to do but became subject to pay these purchased power costs because of the decision of an authority having jurisdiction of the subject matter. I would hold that to disallow the recovery of costs actually incurred, we would need to find a lack of reasonable and prudent action on the part of North Carolina Power.

2. I also dissent from those parts of Findings of Fact 60, 61 and 62 to the extent that they conflict with Commission Rules R12-12 and A12-13. Once again the majority has solved a difficult problem by "splitting the difference" and disallowing half of the alleged competitive advertising because some of the ads made reference to natural gas. While compromise verdicts may be excused where reached by juries, it is my understanding that our

findings of fact must be based upon evidence in the record. They also must be in conformance with our rules.

As I read Rules R12-12(d) and R12-13(c), advertising which comes within any of the six subparagraphs of R12-12(d) will be deemed reasonable operating expenses except to the extent that the expenditures might have exceeded a reasonable amount. There is no reference in either of these rules to competitive advertising. In my opinion, the thrust of the entire co-op advertising company was to promote energy efficiency so that the entire expense would be reasonable under Rule 12-12(d)(1) and (5). If we are going to disallow such advertising because of the Public Staff's contention that ads should not promote the use of electricity over gas, we should amend our rules to specifically disallow such advertising.

The disallowance of the "promotional advertising" by the majority clearly is inconsistent with the definition of such advertising in Rule R12-12(c). The rule defines such advertising as that which encourages the use of electricity where ". . . such appliance, equipment, or service would promote or encourage indiscriminate and wasteful consumption of energy. . . ." Furthermore, such advertising must have a disclaimer to the extent that the advertising is not paid for by the customers of the utility. I would have found this advertising to be recoverable either under Rule R12-12(d) or Rule R12-13(d).

I also have difficulty with the disallowance of the "image advertising" because recovery for such expenses is not precluded by our rules. If such a policy is to be continued, the rules should be amended. Until this is done, I am of the opinion that these expenses should have been recovered under Rules R12-12(d) and R12-13(d).

3. Finally, I dissent from Finding of Fact 63 which disallows half of the compensation of officers. My opinion in this regard is set forth in my dissent in Docket No. E-22, Sub 314 and need not be repeated here. Suf-

fice to say I continue to believe that such disallowance is arbitrary and capricious and beyond the authority granted by law.

/s/ Laurence A. Cobb
LAURENCE A. COBB

APPENDIX D

Order of the Federal Energy Regulatory Commission (February 28, 1990)

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. ER90-80-000

DOSWELL LIMITED PARTNERSHIP

ORDER ACCEPTING RATES FOR FILING, NOTING INTERVENTIONS, AND GRANTING AND DENYING WAIVERS

(Issued February 28, 1990)

Before Commissioners: Martin L. Allday, Chairman; Charles A. Trabandt, Elizabeth Anne Moler and Jerry J. Langdon.

Background

In December 1986, Virginia Electric and Power Company (Virginia Power) solicited proposals from developers of qualifying facilities (QFs) for 700 MW of intermediate and peaking capacity for availability in the

winter of 1990. The solicitation specified energy and capacity charges reflecting the projected costs of Virginia Power's gas-fired combined cycle unit, Chesterfield 7. In response to the solicitation, 27 parties responded with proposals for more than 5000 MW of capacity. Virginia Power executed seven contracts with a total capacity of 1200 MW.

One of the offers accepted by Virginia Power was from Intercontinental Energy Corporation (Intercontinental). Intercontinental offered to construct two 300 MW gas-fired combined cycle units, and Virginia Power executed an agreement for each unit with Intercontinental in 1987.

On June 21, 1989, Intercontinental assigned the agreements to Doswell Limited Partnership (Doswell). Doswell is a limited partnership consisting of one general partner and one limited partner (Doswell I, Inc. and Doswell II, Inc., respectively), which are both wholly owned subsidiaries of Diamond Energy. Diamond Energy is a wholly owned subsidiary of Mitsubishi Corporation.[1]

On November 22, 1989, as supplemented on December 28, 1989, Doswell submitted the two agreements with Virginia Power for filing with the Commission as initial rates.[2] Although Intercontinental initially responded to Virginia Power's proposal as a cogenerator, Doswell is not a cogenerator; rather it is an independent

---

[1] Dowell states that other entities may acquire equity interests in the units, but these entities have not been identified. We note that, according to Doswell's application (at p. 12, n. 13), Diamond Energy is engaged in the development of three other electric cogeneration facilities in Texas, California and New York, none of which will sell to Virginia Power.

[2] The rate schedule designations are:

Doswell Limited Partnership, Inc.
Rate Schedule FERC No. 1 - Unit 1
Rate Schedule FERC No. 2 - Unit 2

power producer (IPP). Doswell requests Commission action on the rate filings no later than March 1, 1990, in order to obtain financing in sufficient time to meet the construction deadlines which are established in the agreements.[3] Doswell also requests waiver of various Commission accounting and reporting requirements.

Provisions of the Agreements

Under the agreements, service is expected to commence in 1991 and continue for 25 years, with possible five-year extensions. There are no minimum take requirements and Virginia Power would schedule energy only when it is economical to do so. The rates for service are intended to track Virginia Power's costs for Chesterfield 7, a gas-fired combined cycle facility which is currently under construction in Virginia.[4] The agreements also specify liquidated damages to be paid to Virginia Power if the units are not in service by December 1, 1991, do not achieve the specified dependable capacity upon installation, or do not maintain at least 85 percent of the specified dependable capacity thereafter.

Doswell cites the cost of Chesterfield 7 as an avoided cost rate for the units because Virginia Power used the projected cost of Chesterfield 7 to design the rates it specified in its solicitation. Moreover, in 1988, the Virginia State Corporation Commission (Virginia Commission) determined that Chesterfield 7 reflected Virginia Power's avoided costs for purposes of setting certain QF

---

[3] On February 7, 1990, Doswell filed a petition for expedited treatment, requesting that the Commission consider the filing at its meeting of February 14, 1990.

[4] The capacity charges would be $10.2567/kW/month for the first 15 years and $5.8933/kW/month thereafter. Payments would be suspended or reduced under various circumstances if the units do not perform as expected. There would also be various other rate components to compensate Doswell for its fuel costs, as well as fuel storage and transportation costs.

contract rates. Doswell argues that its rates should be compared with Virginia Power's avoided costs at the time of the 1987 agreements.

In 1989, Virginia Power revised its gas supply arrangements for Chesterfield 7 and provided Doswell and other gas-fired projects the opportunity to modify their agreements to conform to this revision. Doswell submitted the revised power purchase agreements to the Commission on January 5, 1990. Doswell also submitted on January 16, 1990, an affidavit from Virginia Power certifying that the rates do not exceed Virginia Power's avoided costs.

In support of its argument that the proposed rates are just and reasonable, Doswell states that it lacks, and its predecessor Intercontinental lacked, market power over Virginia Power, and that the rates reflect Virginia Power's avoided costs. In this regard, Doswell states that: (1) Virginia Power can and does build new capacity as necessary; (2) neither Doswell nor Intercontinental could limit Virginia Power's access to other suppliers because (a) Doswell does not, and Intercontinental did not, own or control any transmission facilities except to interconnect its generation facilities with purchasing utilities' systems, and (b) Doswell does not, and Intercontinental did not, own or control any franchised service area or otherwise sell electricity to Virginia Power or to an adjacent utility; and (3) Virginia Power has and will continue to have numerous supply options available, including self-generation. Moreover, Doswell notes that the 600 MW of capacity in this proposal is only four percent of Virginia Power's projected system capacity for 1991.

Doswell cites several safeguards in the 1987 agreements that it believes will ensure that the facilities will be constructed and operated reliably by Doswell. These include requirements for various progress and operating reports, operational covenants, a security deposit, per-

formance testing, a default provision, and an insurance requirement.

Notice of the original and supplemental filings were published in the *Federal Register*,[5] with comments, protests or intervention due on or before December 27, 1989, and January 19 and 23, 1990, respectively. On December 19, 1989, Virginia Power filed a motion to intervene that supports acceptance of Doswell's filing but raises no substantive issues. On December 27, 1989, Tellus, Inc. filed a motion to intervene that raises no substantive issues.

On February 13, 1990, the Virginia Commission issued its Opinion and Final Order in Case No. PUE890068, granting Doswell a certificate of public convenience and necessity for the units. The Virginia Commission noted that: (1) Virginia Power has a need for capacity in the early 1990's; (2) the loss of capacity associated with the Doswell project would leave Virginia Power with a minimal allowance for further attrition of purchased power; (3) the Doswell project is optimally located near a Virginia Power transmission line and the Richmond-Washington corridor; (4) its staff reported that Doswell's rates, based on the avoided costs of Chesterfield 7, are reasonable when compared to payments for power from similar projects; (5) there is no reason to believe that the costs of the project will become unreasonable because the project is no longer a cogeneration facility; and (6) Doswell appears to have the technical ability and financial viability to undertake the project. The Virginia Commission required, as a condition to its approval, that Doswell: file with the state commission copies of its revised, executed power contract and operating contract with Virginia Power; comply with any and all reporting requirements directed by the state com-

---

[5] 54 Fed. Reg. 50,429 (1989), 55 Fed. Reg. 1258 (1990), and 55 Fed. Reg. 1865 (1990), respectively.

mission related to construction, operation and technical aspects of the project; not sell or transfer any of its utility assets or the certificate of public convenience and necessity without first seeking the state commission's approval; and file certain described information, reports and contracts with the Clerk of the Virginia Commission. The Virginia Commission's order also provided that the certificate holder and all general partners of any partnership holding any interest in the certificate, their successors and assigns are subject to all of the regulatory provisions of Title 56 of the Virginia Code which are not preempted by federal law.

Discussion

Under Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (1989)), the timely, unopposed motions to intervene of Virginia Power and Tellus, Inc. serve to make them parties to this proceeding.

Pricing Flexibility

To approve Doswell's proposed market-oriented rates, the Commission must determine that the rates are just and reasonable under section 205 of the Federal Power Act. To determine that the proposed rates are just and reasonable, the Commission must find that they fall within a "zone of reasonableness," where the rates are lower than what would be excessive to consumers and higher than what would be confiscatory to investors.[6] The Commission has allowed pricing flexibility in recent cases, and has concluded that noncost based rates fall within a zone of reasonableness in circumstances where the seller can show that it lacks market power or has mitigated its

---

[6] *See Jersey Central Power & Light Company v. FERC*, 810 F.2d 1168, 1177 (D.C. Cir. 1987).

market power, and there is a pricing cap based either on the seller's costs,[7] or on the purchaser's avoided cost.[8]

In substance, Doswell's rates initially were established in a QF solicitation in which Doswell's predecessor, Intercontinental, participated.[9] However, we cannot accept a QF avoided cost rate as just and reasonable for a non-QF under the Federal Power Act without examining whether market forces were at work to establish the price and nonprice terms agreed to by the parties. Doswell claims that it and its predecessor lack market power over the purchaser, Virginia Power, and has provided a certification from Virginia Power that its rates do not exceed Virginia Power's avoided costs. Based on the information provided in this filing, we find sufficient assurances that the rates fall within a zone of reasonableness.

The agreements between Doswell and Virginia Power arose out of a 1986 solicitation by Virginia Power to many QF developers. According to the solicitation letter, the quantity of electric capacity that was then being proposed by cogenerators and small power producers was significantly greater than the amount of capacity the company needed. As a result, the company told developers that it was withdrawing current offers, rejecting previously

---

[7] *Pacific Gas and Electric Co. (Turlock)*, 42 FERC ¶ 61,406 (1988), *order on rehearing*, 43 FERC ¶ 61,403 (1988); *Pacific Gas and Electric Co. (Modesto)*, 44 FERC ¶ 61,010 (1988), *order on rehearing*, 45 FERC ¶ 61,061 (1988).

[8] *Citizens Power & Light Corporation (Citizens Power)*, 48 FERC ¶ 61,210 (1989); *Ocean State Power (Ocean State)*, 44 FERC ¶ 61,261 (1988); *Orange & Rockland Uitlities*, 42 FERC ¶ 61,012 (1988); *Baltimore Gas & Electric Co.*, 40 FERC ¶ 61,170 (1987).

[9] We note that under its January 3, 1990 agreement with Virginia Power, Doswell reserved the right to obtain QF status anytime in the future without any impact on the purchase prices in the agreement.

received offers, and requesting new proposals from QF developers wishing to contract with it.

The solicitation letter stated that the capacity and energy payments would be based on the estimated costs of the company's planned Chesterfield 7 unit and that full dispatchability would be a prime selection factor. Twenty-seven QF developers responded to the solicitation with offers that resulted in a total offered capacity approximately seven times greater than the amount requested. Virginia Power entered into negotiations with the developers of the competing projects.[10] Upon concluding its negotiations with the competing QF suppliers, Virginia Power selected the seven projects that it believed offered the best packages of terms. Intercontinental, Doswell's predecessor, was one of those seven.

This transaction was clearly the product of a market process. Several factors lead us to this conclusion. First, the buyer, Virginia Power, had discretion over the price and other terms in the deal. This is best evidenced by the fact that its original solicitations, which produced a greater than anticipated supply response, were withdrawn and reoffered in a manner that allowed Virginia Power greater discretion in selecting the winning bids.

Second, the seller, Intercontinental, also had discretion in the transaction. The fact that Virginia Power offered a "take it or leave it" price in no way constrained potential sellers from offering a lower price to improve their prospects for being chosen in the solicitation.

Third, the parties negotiated nonprice factors. Virginia Power's negotiations with the developers focused on what are often referred to as nonprice terms and conditions (*e.g.*, degree of dispatchability, security deposits, performance dates, and penalties for nonperformance). The "non-price" characterization is something of a misnomer because clearly such provisions can have a direct and

---

[10] *See* Petition, Appendix A, Tab 9.

significant impact on the lifetime cost of a project to the buyer.[11] Virginia Power's purpose in pursuing the negotiations with each competing supplier was to obtain a package of the price and other terms that would minimize the total effective cost of that supply option.

All of these factors taken together make it clear that the rate, terms and conditions of this transaction were the product of a multiparty, market-oriented process. Having concluded that there was a market at work, it is next necessary to determine whether Intercontinental or Doswell had market power in this market.[12]

There are several factors that lead us to conclude that both Intercontinental and its successor, Doswell, lacked market power over Virginia Power. First, Intercontinental did not own or control, and was not affiliated with any entity that owned or controlled, transmission facilities within or around the Virginia Power service area, other than those necessary to interconnect with Virginia Power for this sale. Therefore, Intercontinental was not in a position to prevent Virginia Power from reaching competing suppliers. At the time of the assignment of the agreements by Intercontinental to Doswell, the above facts were also true for Doswell.

Second, there is no evidence that Intercontinental or Doswell was a dominant firm in any generating market that might be relevant to providing capacity and energy to Virginia Power. Intercontinental and Doswell were

---

[11] An example may clarify this point. If a project is not completed on schedule, Virginia Power may have to incur the cost of purchasing replacement power to make up for the shortfall in capacity. A contract provision that assesses penalties on the project developer for missing deadlines would mitigate these costs.

[12] Market power for a seller exists when the seller can significantly influence the price in the market by withholding service and excluding competitors for a significant period of time. 48 FERC at p. 61,777. It also exists for a seller that can hold price constant and offer an inferior service while excluding competitors.

new entrants into Virginia Power's market. Neither owns or owned other generating resources in Virginia Power's service area or in any adjacent service area.

Typically, a seller with market power can withhold capacity to raise price in the market. If Intercontinental or Doswell had attempted to withhold service (either by not responding to the Virginia Power's solicitation or by threatening not to sign a contract unless certain demands were met), Virginia Power could have selected one or more of the other respondents at the same price or constructed the capacity itself.

Third, there is no evidence that either Intercontinental or Doswell controlled resources that allowed it to erect any other barrier to potential competing generation suppliers. For example, they did not have sole rights to the last or one of the last viable sites in nor near Virginia for new generation capacity.[13]

In light of these factors, we conclude that neither Doswell nor Intercontinental could have significantly influenced the price Virginia Power paid for new capacity and energy.

We also conclude that there is no evidence of self-dealing [14] because Doswell is not affiliated or involved in any joint venture with its purchaser Virginia Power, nor is it affiliated or involved in a joint venture with the franchised utility in the purchaser's service area (in this case, both the franchised utility and the purchaser are the same entity). However, to ensure that there is no oppor-

---

[13] This is shown by the fact that, in 1988, after it had signed the contract with Intercontinental, Virginia Power negotiated 19 more contracts for a total of 2000 MW of capacity to be constructed at various sites accessible to Virginia Power. *See* Petition at 15.

[14] A problem with self-dealing occurs when an entity sells to or buys from an affiliate on terms that are more favorable than would be available to other market participants.

tunity for self-dealing or other abuses in the future,[15] we will require Doswell to report to the Commission any future affiliate or joint venture dealings with Virginia Power.[16]

In addition to providing support for the conclusion that Doswell has not exercised market power over Virginia Power, Doswell has provided a statement from Virginia Power that Doswell's rates do not exceed Virginia Power's avoided cost. The 1986 solicitation indicated that payments would reflect avoided cost and that avoided cost would be based on Virginia Power's Chesterfield 7 unit. That Chesterfield 7 was an accurate representation of Virginia Power's avoided cost is corroborated by the Virginia Commission's adoption of Chesterfield 7's costs to set avoided cost rates for certain QF contracts in the same time frame involved here.[17] Although Doswell is

---

[15] We note Article 13.6 of the January 3, 1990 agreement between Doswell and Virginia Power gives the utility the right of first refusal to acquire the seller's general partnership equity or assets.

[16] As discussed below, *infra* p. 10, we are also requiring Doswell to report to as any disposition of shares in the partnership to an electric utility or its affiliate. If Doswell engages in these activities, or affiliate or joint venture dealings with Virginia Power, reexamination of Doswell's rates may be appropriate.

[17] In 1988, the Virginia Commission ratified and adopted a final order of an arbitrator which found that avoided cost pricing for four QF projects should be based on Virginia Power's cost of constructing and operating Chesterfield 7 as of November 12, 1987, which was the date the arbitration petitions were filed. *See Petition of Ultra Cogen System, Inc., et al.*, Case No. PUE870088 *et al.*, Award and Final Order of Thomas P. Harwood, Arbitrator, September 30, 1988 and Order Ending Proceeding, November 18, 1988. *See also* Memorandum dated April 27, 1988 from Thomas P. Harwood, Jr. to James C. Roberts, Esq., *et al.* We also note that the Virginia Commission granted a certificate of public convenience and necessity for Chesterfield 7 on July 17, 1987, as amended on September 28, 1988. Doswell Petition filed November 22, 1989, notes 15 and 19. Chesterfield 7 is scheduled to go into service in June 1990.

an IPP rather than a QF, Virginia Power's avoided costs are the same whether the seller is an investor-owned utility, QF, IPP or other marketer. The fact that the price paid to Doswell could not exceed Virginia Power's avoided cost assures us that the rate does not exceed the upper end of the zone of reasonableness.[18]

In sum, we believe that the rates are just and reasonable because there is no evidence that either Intercontinental or its successor Doswell has exercised market power or engaged in self-dealing, and because the rates will not exceed Virginia Power's avoided cost during the same time frame that the Doswell contracts were executed.

---

[18] The issue of whether Doswell is a reliable and least cost alternative goes to Virginia Power's prudence in making this purchase, which is an issue that need not and should not be resolved in this docket. Our finding that Doswell's rate is "just and reasonable" in this filing does not preclude this Commission or the Virginia Commission from examining the prudence of Virginia Power's purchase in a subsequent rate case. The Commission reaffirms its conclusion that the Supreme Court's decisions in *Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953 (1986), or subsequent cases, do not preclude state regulators from reviewing the prudence of a utility's purchasing decisions. While *Nantahala* held that "a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable," 476 U.S. at 966, the Court did not decide the issue whether a state agency can inquire into a utility's prudence in choosing to pay the FERC-approved wholesale rate of another supplier. *See also Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Comm'n*, 837 F.2d 600 (3rd Cir.), *cert. denied*, 109 S.Ct. 365 (1988); *Pike County Light and Power Co. v. Pennsylvania Public Utility Comm'n*, 465 A.2d 735, 737-738 (1983). In addition, our finding here does not preclude the Virginia Commission from examining, as it has done here, the "viability and appropriateness of the Doswell project" in a certificate of public convenience and necessity proceeding (Virginia Commission Opinion and Final Order, Case No. PUE890068, p. 6).

Waivers

Because Doswell's rates are not cost-based, they are not susceptible to certain cost data requirements. Therefore, we will grant Doswell's request to waive the filing requirements under section 35.12(b) for initial rate schedules.

We will deny Doswell's request to waive the requirements in Part 33 of our regulations (regarding dispositions, mergers and consolidations of facilities, and acquisitions of securities of a public utility) without prejudice to Doswell's refiling the waiver request at the time that Doswell may engage in such a transaction. In addition, we will require Doswell to report to us any disposition of shares in the partnership to an electric utility or its affiliate. This requirement will allow the Commission to monitor any affiliations that may involve instances of self-dealing or other abuses.

Doswell also requests waiver of Parts 41, 101, and 141 of our regulations (regarding accounting and reporting requirements); Part 50 (regarding procurement policy and practices); an abbreviated filing under Parts 45 and 46 (prescribing filing requirements for interlocking directorates); and blanket approval under Part 34 of all future issuances of securities and assumptions of liability by Doswell.

We will grant these waivers to the same extent as we did in *Citizens Power*. *Doswell* describes itself as a special purpose, one-asset entity that has not developed and does not presently own any other energy propects or facilities. The only transmission facilities that Doswell owns or controls are those used to interconnect its generating facilities to its purchaser, Virginia Power. Based on its limited holdings and purpose, we believe that these requirements may be unnecessarily burdensome.

Finally, we will grant Doswell's request to waive the advance notice requirements in section 35.3 of our regulations, given the expressed financing and construction

contingencies. The rate schedules shall become effective as of the date of this order.

The Commission orders:

(A) Doswell's initial rates are hereby accepted for filing to be effective as of the date of this order.

(B) Doswell shall report to the Commission any future affiliate or joint venture dealings with the Virginia Power.

(C) Doswell's request for waiver of Part 33 of the Commission's regulations is hereby denied without prejudice, as provided in the body of this order. Doswell shall report to the Commission any disposition of shares in the partnership to an electric utility or its affiliate.

(D) Doswell's request for waiver of section 35.12, and Parts 41, 50, 101, and 141 of the Commission's regulations is hereby granted.

(E) Within thirty (30) days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liability by Doswell should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214).

(F) Absent a request for hearing within the period set forth in Ordering Paragraph (E) above, Doswell is authorized to issue securities and assume obligations or liabilities as guarantor, endorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the applicant, and compatible with the public interest, and is reasonably necessary or appropriate for such purposes.

(G) The Commission reserves the right to require a further showing that neither public nor private interests will be adversely affected by continued Commission approval of Doswell's issuances of securities or assumption of liability.

(H) Until further order of this Commission, any person now holding or who may hold an otherwise proscribed interlock involving Doswell is authorized to hold such position provided that such person files the application required by Ordering Paragraph (I) below.

(I) Until further order of this Commission, the full requirements of Parts 45 and 46 of the Commission's regulations, except as noted below, are hereby waived with respect to those persons subject to Ordering Paragraph (H) above, and those persons instead shall file a sworn application providing the following information:

(1) full name and business address; and

(2) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(J) The Commission reserves the right to require a further showing that neither public nor private interests will be adversely affected by the continued holding of the interlocks addressed above.

(K) Doswell's request for waiver of section 35.3 of the Commission's regulations is hereby granted.

Commissioner Trabandt *concurred* with a separate statement attached.

Charles A. TRABANDT, Commissioner, *concurring*:

I agree that the Commission should approve the arrangement under which Doswell Limited Partnership (Doswell) will sell electricity to Virginia Electric and Power Company (VEPCO), although I would add to the conditions the order contains. In addition, while I find

the rate just and reasonable under the Federal Power Act, I do so for different reasons from those the order offers, *see particularly,* slip op. at 6-7. I explain below that I cannot embrace as readily as the majority the notion that the sale price, which VEPCO announced in advance it would pay, resulted from the push and pull of a market.

Nevertheless, other facts in the record lead me to support the outcome of this order. I also note that the novelty of electric power procedures at the time VEPCO sought suppliers argues in favor of approving the resulting contract. Considering the state of sophistication on these matters in those days, the parties have done their best and enough to satisfy the Federal Power Act. Because the difference in rationale involves more than a quibble over legal niceties, I write to explain my position.

1. Why the Market Rationale Squeezes the Contours of the Just and Reasonable Standard

In my concurring opinion in *Citizens Power & Light Co.,* 48 FERC ¶ 61,210, at pp. 61,782-61,786 (1989) and my dissent in *Ocean State Power,* 44 FERC ¶ 61,261, at pp. 61,988-61,993 (1988), I wrote at length on how the Commission may legally approve as just and reasonable under the Federal Power Act rates that the Commission would reject as too high under traditional individual cost regulation. I specifically refer the reader there for the full discussion.

For purposes of this opinion, keeping in mind the D.C. Circuit case law—(1) the rate must emerge from negotiations in a truly competitive market; (2) the Commission must establish a rate ceiling; and (3) the order approving the rate must contain a mechanism to monitor the situation—suffices. In addition, the Supreme Court in *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 775-777 (1968) (involving the Natural Gas Act's identical just and reasonable standard), held that where the Com-

mission can show individual cost calculations infeasible, the agency may draw from a larger sample of sellers, such as an area or the Nation. Therefore, the Commission may extrapolate individual rates from such composite figures, in place of the costs of the particular regulated company.

The order holds that the Doswell-VEPCO contract meets the criteria the Court of Appeals established. The discussion acknowledges, slip op. at 5, that "Doswell's rates initially were established in a [Public Utility Regulatory Policies Act (PURPA)] solicitation in which Doswell's predecessor . . . participated." That statute allows (and our regulation requires) utilities to purchase electricity from qualifying facilities (commercial sellers of steam or users of renewable energy, collectively, called QFs) at the purchaser's "avoided cost," the price the buyer would have paid for a substitute source—in this case, building a plant itself.

Because Congress established that rate as the maximum for qualifying facilities, whether or not that would pass under the just and reasonable test has no relevance. However, Doswell, which began as a QF, literally lost its steam host (the intended consumer of the steam a QF produces in the cogeneration process), and comes to us as a no-frills generating plant. Therefore, the order, *id.*, correctly states, "we cannot accept a[n] avoided cost rate as just and reasonable . . . under the Federal Power Act without examining whether market forces were at work *to establish the price* and non-price terms. . . ." (Emphasis added.)

In addition, the order points out that the original solicitation that drew Doswell's predecessor to VEPCO contained a fixed price, (i.e., the avoided cost maximum PURPA rate) set in advance. VEPCO stated it would pay suppliers a rate equal to the cost of the most recent plant the utility had sought approval to build. Therefore, VEPCO's avoided cost here represents the highest

price any buyer would pay. No rational company would pay someone else more than what the buyer would have to expend to build for itself. As "what the market will bear," that amounts to an unjust and unreasonable rate.

I would note at this point that the courts have recognized, even in affirming the Commission's desision to require rates for QFs to equal avoided cost (unless the parties negotiate a lower figure), that PURPA represents a special case, the exception to the "just and reasonable" rule. When the D.C. Circuit originally considered the Commission's PURPA rate regulations, the court reversed.

The panel held that because PURPA mandates that QF rates also be "just and reasonable to the electric consumers of the electric utility," and "in the public interest," the law required the Commission to consider a rate level lower than the maximum amount, so that consumers may share the benefits of the QF transaction. The court held that competition among QF's may lead to lower rates. *American Electric Power Corporation v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd sub nom. American Paper Institute v. American Electric Power Corporation*, 461 U.S. 402 (1983). The Supreme Court rested its reversal of the Court of Appeals on the argument that the Commission properly gave content to congressional intent to encourage PURPA projects. The Court did not hold avoided cost just and reasonable. Therefore, I am satisfied, as the order concludes, slip op. at 5, that, an avoided cost rate from a seller not a QF, does not inherently qualify as just and reasonable.

Nevertheless, the order approves Doswell's avoided cost rate. The majority, slip op. at 6, finds a market "process" established the price, thus, on the surface, providing further analysis. However, the analysis consists of the following reasons: (1) VEPCO *could have asked* for a different price; (2) Doswell *could have offered* another price; and (3) the two negotiated *nonprice* "factors." I respond: (1) VEPCO did not; (2) Doswell (or any

buyer guaranteed a price) would not; and (3) while non-price terms may "affect the lifetime cost of [the] project," (*id.*), the parties did not negotiate the price itself. In effect, Doswell('s predecessor) began as a QF and kept its PURPA rate when it turned into a conventional generating plant. The order notes, slip op. at n.9, that Doswell may again become a QF (I presume if it finds a purchaser for its steam), entitled to an avoided cost rate.

As far as its Federal Power Act analysis, the order starts out with the proper intention but misses in the execution. Here lies my concern. The majority today approved the Doswell-VEPCO contract as the product of price negotiations. The Commission will have to strain the next time to reject a filing that contains an avoided cost term for a seller: (a) owning a plant (unlike *Citizens* which only took title to electricity) but; (b) not affiliated with the purchasing utility; and (c) having no market power over it. In short, what the majority tailored today provides a perfect fit for an independent power producer (IPP) obtaining preferred rate treatment, i.e., perforce an avoided cost rate without undergoing a market process.

Additionally, the court in *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168 (D.C. Cir. 1987), which, this order cites, slip op. at 4-5, requires that the Commission "assure itself . . . that 'each of [a rate] order's essential elements is supported by substantial evidence'. . . ." 810 F.2d at 1177, quoting *Permain*, 390 U.S. at 792. Here, the order creates a market out of mere conjecture for which I find no evidence in the record. Clearly, to establish the market-based competition necessary to support this particular avoided cost rate, the Comission should have facts, data and evidence, not hypothetical possibilities.

I also note, as I have in *Ocean State*, 44 FERC at p. 61,989, that the Notice of Proposed Rulemaking on IPP's proposed avoided cost as one of three possibile

ways to set prices for that type of electricity. As I stated earlier, bidding has advanced since this solicitation occurred, so I assume we will never see a contract with a predetermined price in the future. Nevertheless, the precedent lurks in the Reports for possible misuse later.

Moreover, as I now explain, I think the Commission could have reached its result on a narrower, and safer, basis.

2. The Alternate Route to Approval

The Supreme Court in *Permian* held that the Commission may, under the just and reasonable standard depart from individual cost regulation for gas producers and substitute instead rates that the agency calculated in the aggregate. The Court held, 390 U.S. at 777, that the Commission may make " 'pragmatic adjustments which may be called for by particular circumstances.' " (quoting *FPC v. Natural Gas Pipeline Co. of America,* 315 U.S. 575, 586 (1942)), as long as the statute does not prohibit it. For gas producers, the Court agreed that the Commission could not use individual costs.

In that context the Court held that regulation "may . . . depend upon the contrivance of [different] administrative methods." 390 U.S. at 777. In the case before us, we do not have Doswell's actual costs, for the price its contract with VEPCO calls for—indeed, the entire solicitation—bears no relation to that. Nevertheless, the Virginia Corporation Commission has provided an adequate substitute. That agency reviewed the Doswell-Virginia Power contract in the course of its certificate proceeding, as the order recites in its "Background" section, slip op. at 4.

The state commission found that while the rates are not cost-based as far as Doswell is concerned, the state noted that its staff found them reasonable for this type of project, as a free-standing generator. (State commis-

sion order at 12). In effect, the state's experts allow us to find the rate just and reasonable in the aggregate. While the Federal Power Commission spent years amassing area cost data, neither Doswell nor VEPCO can wait that long and I hold that determination adequate here.

The state commission also rested its decision to issue a certificate on the following findings: that Virginia Power has a need for Doswell's electricity; that Doswell is a viable entity capable of operating a generation facility; that the Virginia staff found the rates reasonable for this type of project; and that Doswell made the necessary arrangements for securing financing and fuel for this project. (State commission order at 12-14). In *Ocean State*, 44 FERC at p. 61,984, we relied on (what I thought invalid or untested) state findings as to the reasonableness of the avoided cost rate. So would I here rely on (what I find proper) state determinations, even though in neither case did the state review the rates for purposes of approving the sales.

A broader principle also is at issue in this case: how much weight or significance should this Commission give to the analysis and conclusions of jurisdictional state commissions as to the reasonableness of the rate (especially if the parties negotiated it) for an IPP's wholesale sales? I would attach significance to any such conclusion, whether it be a conclusion that the rate was reasonable (as here) or unreasonable (as it might be in another future case). The order discusses the Virginia Commission's findings, but only as background information, without expressly identifying it as a specific factor in this Commission's analysis and conclusion.

While the Federal Power Act requires that this Commission ultimately must render a judgment as to the justness and reasonableness of a proposed IPP rate, I am persuaded that we may legally take into account the analysis and conclusions of jurisdictional state commis-

sions, where available. Indeed, I believe that fundamental comity between federal and state authorities in this virgin area of shared responsibility virtually demands that FERC place an appropriate significance and weight on any relevant state commission analysis and conclusion as to the reasonableness of the IPP's rate.

In a similar vein, I am pleased to note that the Commission has expressly declared, slip op. at 9-10, n. 18, that under applicable federal law, the state commission has the authority to approve the prudence of the electric utility's purchases from the IPP. If the future generation sector of the evolving electric utility industry includes a substantial number of IPPs in the generation mix as some experts predict (and many others hope), then it will be imperative that state commissions have the authority to scrutinize the prudence of utility purchasing practices in the selection of power purchase contracts necessary to provide the assured and reliable supply to satisfy the franchise utility's obligation to serve its customers. The Commission's clear and unambiguous declaration here that the Virginia Commission shall have exactly such authority in this first real IPP rate case should go a long way legally to establishing that result.

I would also attach some significance to the fact that VEPCO renegotiated with Doswell in late 1989 the original contract setting the avoided cost rate, which Intercontinental Energy (the original QF project sponsor which VEPCO selected in the QF solicitation but lost its steam host) assigned to Doswell in June 1989. By the time of the renegotiation, which retained the original avoided cost, VEPCO had completed two additional solicitations for power purchases under guidelines the Virginia Commission established in early 1988. The new guidelines included price competition in the bidding process. Thus, as of late 1989, VEPCO (as well as the Virginia Commission) had the benefit of an extensive price competition data bank for purposes of assessing

the reasonableness of the avoided cost rate set for the Doswell project as of January 1990.

Furthermore, the particular avoided cost rate was established based on the projected costs of VEPCO's own Chesterfield 7 unit in 1986 and 1987, but subsequently construction of that unit has been completed. Consequently, VEPCO, the Virginia Commission and this Commission have current and comparable avoided cost-based data on which to assess this rate. Thus, I am satisfied that there are sufficient grounds and substantial evidence to conclude that the Doswell rate is reasonable.

I would also address one final point. I note that the Virginia Commission, at pp. 8-10 of its order, discusses imposing on Doswell the usual state reporting requirements, in light of federal preemption of Doswell's rates to Virginia Power. The Virginia Commisison concluded that "while we have no immediate power to respond to Doswell's security issuances or to its dealings with affiliated interests, we have a vital concern in these subjects because of their potential involvement in future FERC proceedings of interest to th[e state]." Order Issuing Certificate at 8-9.

Even while recognizing that the pre-emption doctrine prevented the state from regulating Doswell's rates, the Virginia Commission required the IPP to file information on "the issuance of stocks and stock certificates or other evidences of interest or ownership, and bonds, notes and other evidences of indebtedness and the creation of liens" on the Doswell property within Virginia (*id.* at 9). The state also required Doswell to report "all contracts or arrangements described in Virginia Code § 56-77 and amendments thereto." *Id.* at 10.

The Virginia Commission concluded that neither the Constitution, the Federal Power Act or the court cases prevented it, in the exercise of its licensing jurisdiction, to impose those reporting requirements. The Virginia

Commission also found, *id.*, that those requirements of themselves will not frustrate federal law. I agree with the Virginia Commission.

These requirements for information help strengthen the monitoring mechanism the courts require, either because the information allows Virginia to file a complaint to open a proceeding or to participate more fully in one someone else initiates. On the understanding that the state will not assume regulatory authority that the Federal Power Act lodges in the Commission, I would add these filing requirements to our approval of the rates Doswell brings here. The state needs the information to make our monitoring work better and I think we can use all the help parties offer.

I would prefer the order contain these suggestions, but, in any event, I concur in approving Doswell's rate filing.

APPENDIX E

Order of the Virginia State Corporation Commission (February 26, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

At Richmond, February 26, 1988

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc., in Altavista, Virginia

---

Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEM, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, in Hopewell, Virginia

---

Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEM, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc., in Buena Vista, Virginia

---

Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc., in Franklin, Virginia

---

Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc., in Covington, Virginia

---

Case No. PUE870096

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Mineral Management Systems, Inc., in Algoma, West Virginia

---

Case No. PUE870097

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION AND FCS DEVELOPMENT CORP.

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Davis, West Virginia

---

Case No. PUE870099

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for two small power production facilities located at United Coal Company at Big Rock, Virginia and Richlands, Virginia

---

ORDER

Oral argument on these matters was heard by the Commission on February 25, 1988. The parties and the Staff were ably represented by counsel, and their respective positions were clearly enunciated. The Commission found this argument very helpful in reaching its decision.

The Commission will not engage in a lengthy recapitulation of the issues, or of the positions taken thereto. Rather, we shall proceed to enunciate succintly our conclusions.

These 8 cases are part of the fourteen pending petitions for arbitration representing approximately 759 megawatts of capacity.

These petitions were filed by the qualifying facilities against Virginia Power in reliance upon our orders of January 11, 1983, in Case No. PUE800102, and November 15, 1985, in Case No. PU830067.[1] That reliance was not misplaced. By this order the Commission announces that it will arbitrate to a conclusion those

---

[1] In those orders, the Commission held that, for large qualifying facilities, it would arbitrate disputes among parties who otherwise were unable to reach acceptable contractual arrangements. We found that such action was an appropriate means of implementing § 210 of PURPA and the associated federal regulations. Those regulations provide, *inter alia*, that State commissions may comply with the PURPA mandate by "undertaking to resolve disputes between qualifying facilities and electric utilities. . . ." 18 CFR § 292.401(a).

legitimate disputes pending and ripe for arbitration as of the date of this order, and will do so in a fair and expeditious manner, with the expected cooperation of the parties.

Arbitration is an arrangement for resolving a disputed matter which is an alternative to the formalities of established legal tribunals and litigation. The Commission intends to approach these arbitrations in an innovative fashion, designed to deal with the subject in the prompt, but effective, manner that it warrants. In this light, it is inappropriate for the Commission to sit as a body conducting its traditional quasi-judicial or legislative proceedings. Instead, the Commission, pursuant to PURPA procedures and the implementing regulations thereto, hereby designates Commissioner Thomas P. Harwood, Jr. to serve as arbitrator in these petitions.

We expect the outcome of this arbitration to develop specific terms and conditions of appropriate contracts for capacity purchases by Virginia Power from petitioners. The actions of Commissioner Harwood, and the conclusions he reaches, will be final. The outcome will be binding on Virginia Power in that the utility will be required, pursuant to its obligations under PURPA, to execute those contracts found to be reasonable by the arbitrator. His actions will likewise be binding on the qualifying facility if it expects to contract with Virginia Power in these cases. PURPA, of course, imposes no *obligation* on cogenerators to sell their capacity or energy.

Our order of January 29, 1988, in Case No. PUE870080, promulgated no rules and mandated no course of action to be followed by Virginia electric utilities in acquiring generating capacity from qualifying facilities. That order did identify "bidding" by potential cogenerators as an acceptable means of complying with PURPA, but the decision to use such a procedure, and the process of selecting from among the actual bidders, is left to the utilities. We suggested, however, that the

utilities consider what we termed "competitive negotiation."

Competitive negotiation envisions the issuance by the utility of a form of "Request for Proposals" ("RFP"), and we outlined some suggested factors, or criteria, which might be incorporated in an RFP. The factors would be expected to vary from time to time, depending on both internal and external conditions.

Virginia Power is not precluded at this time from proceeding to solicit additional generating capacity by means of some version of an RFP. It must be understood, however, that further solicitation at this time shall be subject to the outcome of the arbitration herein provided. That is, the amount of capacity potentially to be contracted for under any RFP will be limited by the amount of capacity for which contracts have been executed as a result of the arbitration process. Should Virginia Power decide to go forward with its previously announced efforts, the petitioners may freely participate therein without fear of prejudicing the arbitration processes at this Commission. The desirability of such dual participation is a matter for their determination.

ATTESTED COPIES of this order shall be mailed to Richard D. Gary, Esquire, P.O. Box 1535, Richmond, Virginia 23212; John E. Cunningham, Esquire, Manager-Regulation Services, Virginia Power, P.O. Box 26666, Richmond, Virginia 23261; Edward L. Flippen, Esquire, Mays & Valentine, P.O. Box 1122, Richmond, Virginia 23208-9970; and to the Commission's Directors of Energy Regulation and Economic Research and Development and the General Counsel.

A True Copy:

Teste:

/s/ George W. Bryant, Jr.
Clerk of the
State Corporation Commission

APPENDIX F

Decision on Pricing Issue, Thomas P. Harwood, Jr., Virginia State Corporation Commission (April 27, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

April 27, 1988

Richard D. Gary, Esq.
Hunton & Williams
P.O. Box 1535
Richmond, Virginia 23212

James C. Roberts, Esq.
Mays & Valentine
P.O. Box 1122
Richmond, Virginia 23208-9970

Re: Virginia Power and Ultra Cogen Systems Arbitration. Case Nos. PUE870088 et al.

Gentlemen:

Enclosed is my decision on the pricing issue. The memoranda and oral argument were most helpful, and for them I thank counsel.

The negotiation sessions may now progress, and they should be held more often than once a week.

I expect to meet briefly with counsel at 9:00 a.m. this Friday, April 29, and at 4:00 p.m. on Friday, May 6. Status reports will continue to be due by 5:00 p.m. on April 29 and May 6.

The parties should amicably resolve any remaining issues.

Sincerely,

/s/ Thomas P. Harwood, Jr.
THOMAS P. HARWOOD, JR.

TPHjr:lmc

cc: Edward L. Flippen, Esq.
John E. Cunningham, Esq.
William G. Thomas, Esq.
William S. Bilenky, Esq.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

MEMORANDUM

DATE: April 27, 1988

TO: James C. Roberts, Esquire
Edward L. Flippen, Esquire
Richard C. Gary, Esquire
William G. Thomas, Esquire
John E. Cunningham, Esquire

FROM: Thomas P. Harwood, Jr., Arbitrator

RE: Pricing Issue, Virginia Power and Ultra Cogen Systems ("UCS"), Case Nos. PUE870088, et al.

In seeking to discharge my responsibilities as arbitrator in these matters, pursuant to my appointment by Order of the State Corporation Commission, dated February 26, 1988, I have carefully considered the record in this proceeding. That record includes the briefs of the parties, and the Attorney General as *amicus*, followed by oral argument on April 25, 1988, in which the parties debated for my benefit the very fundamental issue in this arbitration of how to calculate the appropriate payments to UCS for the power it expects to deliver to Virginia Power from its proposed generating facilities. It seems agreed that I am to resolve the stalemate on this point by directing a suitable methodology to be followed.

In seeking to surmount this pricing hurdle, I have also had the benefit of the discovery materials exchanged between the parties, the previous meetings I have held with them, and the minutes and progress reports of those work sessions which were held by the parties, alone, at my direction. I have also reviewed the Notices of Proposed

Rulemaking of the Federal Energy Regulatory Commission which were issued on March 16, 1988, in Docket Numbers RM88-5-000 (Regulations Governing Bidding Programs) and RM88-6-000 (Determination of Avoided Costs), together with the Final Report of the Commission's Avoided Cost Task Force, dated October 8, 1987.

An evaluation of the foregoing leads me to the following findings and conclusions:

I first find that the UCS projects are entitled to a determination of avoided cost payments as of November 12, 1987, the date on which UCS began to file its arbitration petitions with the Commission. Short of a written contract, which does not exist even now, and which is not a necessary prerequisite to the commencement of the purchase obligation under PURPA, see *Snow Mountain Pine Company vs. Maudlin,* 734 P.2d. 366 (Or.App. 1987), the filing of these petitions constitutes the latest possible date on which UCS became "obligated" to provide power to Virginia Power, in the sense that that term is used in PURPA.

I next find that avoided cost payments should be based on Virginia Power's costs of constructing and operating Chesterfield Unit No. 7, as projected on that same date, November 12. It has been the posture of Virginia Power for some time that Chesterfield 7, a gas-fired plant, could, and should, serve as a basis for the Company's avoided cost calculations since that unit is intended to be the prototype of any new capacity to be built by the Company through the mid-1990's, and perhaps beyond. See, *Application of Virginia Electric and Power Company* (Chesterfield 7 approval), Case No. PUE860058, Transcript, June 17, 1987, pp. 642-643.

The minutes of the parties' meeting on April 19, 1988, also contain a statement from Virginia Power that "its costs to construct, own, and operate a facility similar to Chesterfield 7 would represent a cap on avoided costs".

Finally, Virginia Power's recent claims that UCS's proposal would cost ratepayers some $2.0 billion "more" over a 25-year life cycle was apparently tied closely to figures related to Chesterfield 7 and the Company's December 23, 1986, solicitation which was based on those figures.

In making this decision, I am, of course, rejecting Virginia Power's position that the results of the bidding procedure currently underway should serve to determine appropriate avoided costs. I find this position untenable. As noted above, UCS's legal entitlement to an avoided cost contract arose as of November 12, 1987. By contrast, the figures related to Virginia Power's proposal are not known even today, and will not be known for some time. This matter must be resolved now, however, and not at some indefinite future date. I further find that adoption of Virginia Power's proposal herein would be contrary to the Order of the Commission, dated February 26, 1988.

The gas-fired Chesterfield 7 scenario is thus to serve as the determinative factor for avoided costs. The calculation of exact amounts to be paid for energy and capacity using this methodology will, of course, be the responsibility of the parties, which I expect to be discharged promptly by the devotion of all necessary resources. In this endeavor, we are all mindful that there will be differences in the operational parameters of UCS's coal-fired plants, as compared to Chesterfield 7. For example, a coal plant, with lower fuel costs, will presumably have a higher capacity factor and will be utilized on the system on a more frequent basis than a gas plant. In this respect, I call attention to the statement made at the April 19, 1988, meeting that "the critical issue is the projects' effect on total system cost, and the division of the total payment stream from Virginia Power between energy and capacity is generally up to Ultrasystems".

In determining fair payment—consistent with PURPA—I would suggest that it should be useful to develop

various life-cycle revenue streams associated with Chesterfield 7, assuming differing capacity factors such as 60%, 70%, or 80%, with the costs awarded to these coal plants being based on the most likely of those scenarios for the particular projects. The ultimate objective, of course, is that ratepayers pay no more over the life of these plants than they would have paid had the need been supplied by facilities like Chesterfield 7, in lieu thereof, taking into account the differing capacity factors attributable to coal plants, and recognizing that, as more coal plants are added, they will begin to take on the characteristics of base-loaded facilities, rather than the more lightly-loaded design features of Chesterfield 7.

Finally, the parties should *not* understand this decision to be an approval of the December 23, 1986, so-called "solid fuel offer." The minutes of the April 19, 1988, meeting appear to me to demonstrate that the latter was not equivalent to the Chesterfield 7 plant, itself. Rather, my decision is to focus on *Chesterfield 7* and the appropriate equivalent payment streams arising out of the projected figures associated with that plant, and an emphasis on the solid-fuel offer would not be a suitable means of complying with this directive.

With this pivotal issue resolved, I see no reason why the parties cannot now move to a mutually successful conclusion of these negotiations. I expect to be fully and promptly apprised of any further sticking point, but I am determined that there shall be no unjustified delays.

/s/ T. P. H.

cc: William S. Bilenky, Esquire

APPENDIX G

Interim Order of the Virginia State Corporation Commission (May 27, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc. in Altavista, Virginia

---

Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, Hopewell, Virginia

---

Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc. in Buena Vista, Virginia

---

Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Franklin, Virginia

---

Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Covington, Virginia

---

Case No. PUE870096

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Mineral Management Systems, Inc. in Algoma, West Virginia

---

Case No. PUE870097

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION AND FCS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Davis, West Virginia

---

Case No. PUE870099

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for two small power production facilities located at United Coal Company, at Big Rock, Virginia and Richland, Virginia

---

INTERIM ORDER

Ultra Cogen Systems, Inc. and Ultrasystems Development Corporation (collectively "UCS") filed these Petitions for Arbitration between November 12, 1987 and December 3, 1987 requesting the Commission to order Virginia Power to enter into power purchase agreements with UCS. Virginia Power opposed the Petitions. By Order dated February 26, 1988 the Commission found that UCS properly relied on earlier Commission orders and designated that I should serve as arbitrator with regard to those Petitions that represented legitimate disputes pending and ripe for arbitration as of February 26, 1988.

Under my direction, representatives of UCS and Virginia Power initiated negotiations to narrow, if not eliminate, the issues that stand between the parties and the execution of power purchase agreements for the facilities underlying the Petitions for Arbitration. The negotiations were stymied by a disagreement as to the fundamental issue of how to calculate the appropriate payments to UCS for the capacity and energy it expects to make available to Virginia Power from UCS' proposed generating facilities. To resolve that issue, I required a hearing on April 25, 1988 and issued my opinion on April 27, 1988. In essence, I required the pricing proposal to be based on Virginia Power's cost of constructing and oper-

ating Chesterfield 7 as those costs were projected on the first date these Petitions for Arbitration were filed, November 12, 1987. I required that consideration be given to the capacity factors projected for the UCS units and Chesterfield 7 and my objective was that Virginia Power's ratepayers should pay no more over the life of these UCS generating facilities than they would have paid had the need been supplied by facilities like Chesterfield 7.

The proper payments that respond to my directive of April 27, 1988 are contained in Attachment A to this Interim Order, along with other key terms and conditions that should be included in a power purchase agreement between the parties. I direct that these provisions in Attachment A, which I find to be required by the Commission's and my earlier rulings, must be reduced to written agreements. I shall leave these dockets open until the power purchase agreements have been finalized so that I may review their terms and conditions to assure that they comply fully with our mandates in these proceedings. The parties should notify me when such final power purchase agreements have been reached, and I will review these agreements. The parties have also agreed that the number of UCS projects to be considered by the Commission should be reduced to four and, upon entry of the final order, UCS shall withdraw the Petitions for Arbitration in Case Nos. PUE870096, PUE870097 and PUE870099. Further such final order will contain a provision requiring UCS within a period of 6 months after its entry to withdraw one additional Petition. I shall issue final orders in all of these proceedings at the appropriate time consistent with this Interim Order.

/s/ Thomas P. Harwood, Jr.
THOMAS P. HARWOOD, JR.

May 27, 1988

ATTACHMENT A

RESOLUTION OF MAJOR ISSUES ULTRASYSTEMS PROJECTS

1. *Pricing*

   a. *Capacity Price*

   For each of the four projects, the Capacity Price shall be $341.23 per dependable kilowatt for the first 15 years of operation and $189.70 for years 16 through 25.

   b. *Energy Price*

   (1) *Base Price.* The average energy price in 1991 dollars for four projects shall be 2.192 cents/kwh, inclusive of variable operating and maintenance expenses and line losses. Distribution among the projects shall be at Ultrasystems' discretion.

   (2) *Escalation.* During the first 8 years of commercial operation, energy prices will be escalated at 4.1% per annum. On or before the eighth anniversary of commercial operation, the parties will agree to a new base energy price to be effective on said eighth anniversary, which base price will reflect the actual escalation which occurred over the preceding 8 years. At that time, the parties will also agree to market (not in-system coal) based index or series of indexes to be used thereafter. The base price and escalation index(es) shall be reexamined every three years thereafter to reflect actual market conditions.

   c. *Capacity Price Adjustment*

   The Capacity Price in years 16-25 will be adjusted upward or downward by $5.00/kw for

every tenth of a percent that the rate of inflation, as determined by the compounded annual change in the GNP Implicit Price Deflator, exceeds 5.3 percent or is below 4.3 percent, respectively during years 1-15 of the term of the agreement.

2. *Dispatchability*

The facilities will be subject to economic dispatchability, consistent with the following design limits:

(a) Maximum output is 57 MW for Buena Vista, Covington and Hopewell; 55 MW for Franklin and Altavista.

(b) Minimum ramp time is 200 kw/minute up; 500 kw/minute down.

(c) Minimum run time between shutdowns is 12 hours; cannot change direction of dispatch more than twice in any 24 hour period or shut down more than 40 times per year.

(d) Minimum load is 35% of maximum.

(e) Notices: Minimum 8 hours for cold start or full shutdown; 15 minutes for all others; second notice of 30 minutes before forced outage begins.

3. *Forced Outage Damages*

At the end of each agreement year, the actual availability of each facility will be determined, based on the number of hours of forced outage (excluding force majeure) with failure to respond to dispatch after second notice within 5% being considered a forced outage. For each hour for which the facility is unavailable, after an allowance for scheduled outage hours (30 x 24) and an allowance for free forced outage hours (33.5 x 24), Ultrasystems will refund the annual Capacity Payment pro rata at the

rate of 1.5 hours for every hour of such excess outages until such excess outages exceed 50% of total hours in excess of the free forced outage allowance, at which point the entire Capacity Payment for the year will be refunded. Refunds will include interest.

4. *Force Majeure*

Upon declaration of a Force Majeure by Ultrasystems, Virginia Power may immediately suspend Capacity Payments for the duration in days of the Force Majeure. Ultrasystems may, however, choose to use all or any portion of its free forced outage allowance for all or any portion of the Force Majeure days.

5. *Capacity Reduction Damages*

a. *Commercial Operation.*

If, upon commercial operations testing, a facility's actual capacity is less than 90% of the maximum capacity specified in 2 above, Ultrasystems shall pay $15 per kw for the difference below said 90% level.

b. *Seasonal*

If, upon seasonal testing, the capacity is below 85%, Ultrasystems will pay 21.60 per kw below 85% prorated daily. Ultrasystems may call for retests without penalty, but no more often than once in 30 days.

6. *Security*

a. *Pre-Commercial Operation*

(1) A letter of credit or other security reasonably acceptable to Virginia Power, in the amount of $5/kw for each facility. will be posted on the later of 6 months from the

execution of the letter agreement or 60 days from execution of the final contract.

(2) The security instrument shall be increased to $10/kw on the earlier of financial closing or 9 months from posting security pursuant to (1) above.

(3) It shall be increased to $15/kw, 6 months after (2) above.

(4) Damages for abandonment are liquidated at amount of security at all times, subject to Force Majeure, except that the $5.00 amount referred to in 6(a)(1) is not subject to Force Majeure or any other contingencies. If commercial operation is delayed more than 6 months, damages are liquidated at 1/12 of security per month for each month of delay thereafter.

b. *Operations*

Pre operations security remains in effect for entire term to cover liquidated damages.

7. *Regulatory Out (Article 18)*

Will be removed from contracts, assuming entry of the contemplated order directing the rates and terms of the contracts.

8. *QF Certification*

Ultrasystems' obligation to maintain QF status is limited to existing criteria and procedures. If significant new criteria or procedures applicable to the facilities are enacted, compliance will not be a condition of the contract.

9. *Interconnection Costs*

Will be borne by Ultrasystems.

10. *Ownership Transfers*

Before transferring a significant (10% or greater) ownership interest other than for financing purposes, Ultrasystems will first offer it to Virginia Power at a price proposed by Ultrasystems. If Virginia Power does not accept within 60 days, Ultrasystems may offer it to others at a price equal to or greater than the proposed price.

11. *Number of Projects*

Agreements shall be entered into for 4 projects within Virginia Power's service territory, with provision for Ultrasystems to substitute projects in at least one agreement, so that Ultrasystems is not required to elect among the 5 proposed projects until 6 months after execution of the Agreements.

12. *Other*

The parties shall use all reasonable efforts to reach final contractual agreement within 60 days, and neither party shall raise any major substantive issue inconsistent with the above or not raised in the markups exchanged on April 15, 1988 and May 11, 1988.

APPENDIX H

Award and Final Order of the Virginia State Corporation Commission (September 30, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

At Richmond, September 30, 1988

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc. in Altavista, Virginia

---

Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, Hopewell, Virginia

---

Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc. in Buena Vista, Virginia

---

Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Franklin, Virginia

---

Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Covington, Virginia

---

Case No. PUE870096

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Mineral Management Systems, Inc. in Algoma, West Virginia

---

Case No. PUE870097

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION AND FCS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Davis, West Virginia

---

Case No. PUE870099

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for two small power production facilities located at United Coal Company, at Big Rock, Virginia and Richland, Virginia

---

Award And Final Order

Ultra Cogen Systems, Inc. and Ultrasystems Development Corporation (collectively "UCS") filed these petitions for arbitration between November 12, 1987, and December 3, 1987, requesting the Commission to order Virginia Power to enter into power purchase agreements (Agreements) with UCS. The Commission ordered Virginia Power on December 18 to file responsive pleadings, and on December 31 Virginia Power filed its responses opposing the petitions.

On January 29, 1988, the Commission entered a final order in *Commonwealth of Virginia At the Relation of the State Corporation Commission Ex Parte, In the matter of adopting Commission Policy regarding the purchase of electricity by public utilities from qualifying facilities*

when there is a surplus of power available, Case No. PUE870080, expressing general approval of the concept of competitive bidding for new power supplies. Relying in part on that final order, Virginia Power filed on February 11, 1988, a motion to dismiss the UCS petitions for arbitraiton. On February 19 the Commission entered an order in this docket scheduling oral argument on the effects of the final order in Case No. PUE870080 on the Commission's previous decisions delineating the relationship between Virginia utilities and qualifying cogeneration facilities and on the UCS petitions for arbitraton.

After hearing oral argument from both parties on February 25, the Commission entered an order on February 26 stating that the Commission would "arbitrate to a conclusion those legitimate disputes pending and ripe for arbitration as of the date of this order." The Commission noted that it intended "to approach these arbitrations in an innovative fashion." By the same order, the Commission designated that I serve as arbitrator with regard to those petitions that represented legitimate disputes pending and ripe for arbitration as of February 26, 1988. My assigned task has been "to develop specific terms and conditions of appropriate contracts for capacity purchases by Virginia Power from petitioners."

Virginia Power and UCS exchanged interrogatories throughout March and April and began moving towards agreement on terms and conditions. Despite their progress, however, the parties disagreed on a fundamental level with respect to pricing and related issues, and they reached an impasse.

On April 20, 1988, both parties, along with the Office of the Attorney General, filed briefs on the pricing and related issues. Virginia Power supported prices based on avoided costs as determined according to the results of its solicitation of competitive bids. UCS argued that prices should be based on avoided costs as determined according to the Commission-approved methodology in

place as of the time UCS obligated itself to supply power to Virginia Power. I rendered my decision in a letter to the parties dated April 27, 1988.

I required the pricing proposal to be based on Virginia Power's costs of constructing and operating Chesterfield 7 as those costs were projected on the first date these petitions for arbitration were filed, November 12, 1987. The ruling required that consideration be given to the capacity factors projected for the UCS units and Chesterfield 7, and the objective was that Virginia Power's ratepayers should pay no more over the life of the UCS generating facilities than they would have paid had the need been supplied by the Company.

In an interim order dated May 27, 1988, I set forth in Attachment A to that interim order the proper payment structure and other key terms and conditions that should be included in the Agreements. I found that the provisions were required by the earlier orders in these proceedings. The interim order noted that the parties had also agreed that only the projects within Virginia Power's territory would be considered by the Commission and that the number of projects would be reduced to four. To assure that only four projects would be the subject of final Agreements between the parties, I found that upon the conclusion of this proceeding, UCS should withdraw immediately the petitions for arbitration in Case Nos. PUE870096, PUE870097, and PUE870099 and that within 6 months after the entry of this Award and Final Order, UCS should eliminate one additional project, thus assuring that only four projects are the subject of final Agreements between the parties. Finally, I issued a second interim order dated September 2, 1988, noting that the parties had reached agreement on all aspects of the Agreements except for the designation of the specific escalation index or indices to be used to adjust the energy price after the eighth year of commercial operation. I requested that the parties finalize the Agreements by

September 23, 1988, and submit them to me by September 26, 1988.

I received a letter from Virginia Power advising me that, although the parties had reached agreement on all issues, a drafting error would prevent them from filing the final Agreements until September 30, 1988.

In accordance with that letter, the parties submitted to me on September 30, 1988, four identical proposed Agreements that required UCS to choose, within six months of the date of this Award and Final Order, the four projects which are to be the subject of the Agreements. I have reviewed the Agreements submitted by the parties on September 30, 1988, and find that they comply with the provisions of Attachment A of the first interim order, are reasonable and in the public interest, and are required by the Commission's and my earlier orders in this proceeding. I recognize that the Agreements reflect negotiations and rulings based on the unique circumstances of these proceedings (including that they are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth), and I commend the parties for their diligent efforts.

I order that Virginia Power execute the four Agreements submitted to me on September 30, 1988 and deliver the same to UCS for execution within one week following the entry of this Award and Final Order. I further order that UCS select the four projects to which the Agreements are to apply within six months from the date of this Order in accordance with the third recital of the Agreements and that Virginia Power designate the applicable Operations Center and Virginia Power office for each project within thirty days thereafter in accordance with the fourth recital of the Agreements.

I order that these Agreements be placed in the Commission's public files on March 1, 1989, along with all other contracts executed during 1988 for power purchases

from qualifying facilities or independent power producers as required by the Commission's orders in Case Nos. PUE800102 and PUE830067.

/s/ Thomas P. Harwood, Jr.
THOMAS P. HARWOOD, JR.

Dated: September 30, 1988

APPENDIX I

Order of the Virginia State Corporation Commission Ending Proceedings (November 18, 1988)

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

At Richmond, November 18, 1988

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc. in Altavista, Virginia

---

Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, Hopewell, Virginia

---

Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc. in Buena Vista, Virginia

---

Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Franklin, Virginia

Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Covington, Virginia.

ORDER ENDING PROCEEDINGS

Commissioner Thomas P. Harwood, Jr. entered an Award and Final Order in this proceeding on September 30, 1988. The Commission hereby ratifies and adopts such Order as the Final Order in this proceeding and there appearing nothing further to be done in these proceedings hereby orders that these matters be dismissed from the docket and the papers placed in the file for ended causes.

ATTESTED COPIES of this order shall be mailed to Richard D. Gary, Esquire, P. O. Box 1535, Richmond, Virginia 23212; John E. Cunningham, Esquire, Manager-Regulation Services, Virginia Power, P. O. Box 26666, Richmond, Virginia 23261; Edward L. Flippen, Esquire, Mays & Valentine, P. O. Box 1122, Richmond, Virginia 23208-9970; William S. Bilenky, Esquire, Senior Assistant Attorney General, Office of the Attorney General, 101 North 8th Street, 6th Floor, Richmond, Virginia 23219; and to the Commission's Directors of Energy Regulation and Economic Research and Development and the General Counsel.

A True Copy

Teste:

/s/ George W. Bryant, Jr.
Clerk of the State
Corporation Commission

APPENDIX J

**Exerpts from the Federal Power Act,
16 U.S.C. §§ 824, 824a-3**

---

16 U.S.C. § 824:

Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities

used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter. . .

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

* * * *

16 U.S.C. § 824a-3:

Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to. . .

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and;

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies

having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views and arguments. . . . Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric eneregy. . . .

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

APPENDIX K

Excerpts From Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 CFR Part 292 (1987)

---

18 CFR § 292.101(b)(6) (1987):

§ 292.101 Definitions.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

18 CFR § 292.303(a) (1987):

§ 292.303 Electric utility obligations under this subpart.

(a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility[.]

18 CFR 292.304 (1987):

§ 292.304 Rates for purchases.

(a) Rates for purchases.

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) Relationship to avoided costs.

(1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) Standard rates for purchases.

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.303(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting for variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

18 CFR § 292.401 (1987):

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) State regulatory authorities. Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilitates and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

APPENDIX L

Order of the Virginia State Corporation Commission (January 11, 1983)

VIRGINIA STATE CORPORATION COMMISSION

Case No. PUE800102
(and former Case Nos. PUE800082 and PUE800083)

January 11, 1983

Commonwealth of Virginia, ex rel.

Ex Parte, in re: Implementation of Federal Rules concerning Cogeneration (and Small Power Production Facilities pursuant to § 210 of the Public Utility) Regulatory Policies Act of 1978 for Virginia Electric and Power Company

FINAL ORDER

Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") mandated that the Federal Energy Regulatory Commission ("FERC") prescribe rules to encourage cogeneration and small power production within one year after its enactment on November 9, 1978. Further, it required that the Commission, after notice and opportunity for public hearing, implement the FERC rules for each electric utility for which it has ratemaking authority within one year from the promulgation of the FERC's rules.

Although the aforementioned rules had not yet been implemented by the Commission, Virginia Electric and Power Company ("Company") filed a proposed Schedule 10 on June 19, 1980, applicable on a voluntary basis to the supply and/or purchase of electricity to or from

any customer with cogeneration or small power production facilities (Case No. PUE800082). On June 20, 1980, Company filed a revised Rider I For Residential Customers—Standby, Parallel, or Small Power Producer Service (Case No. PUE800083).

Company filed a revised Schedule 10 in Case No. PUE800082 on July 8, 1980, which had been amended to reflect the new fuel factor established by Commission order filed June 27, 1980. On October 3, 1980, Company filed another revised Schedule 10 designed to conform to the rate increase in Schedule 6 granted by the Commission in Company's Review of Financial Operations on September 12, 1980 (Case No. PUE800056). This revised tariff was accepted for filing and the public notice requirements were waived by Commission order dated October 22, 1980.

Company filed another revised Schedule 10 on October 23, 1980, which was designed to reflect the changes in base rates and the fuel factor resulting from the initiation of commercial operation of the North Anna Unit No. 2 (considered in Case Nos. PUE790011 and PUE800067). This revised tariff was accepted for filing and notice requirements were waived by Commission order dated November 25, 1980, in Case No. PUE800082.

Pursuant to PURPA § 210 the Commission entered an order on November 20, 1980, establishing the present case (Case No. PUE800102) for the purpose of determining appropriate rates and provisions for cogeneration and small power production facilities under said section for Company. By the same order, the Commission scheduled a public hearing for January 26, 1981, and directed Company to file proposed rates and information relating to the development of rates pursuant to § 210.

On December 19, 1980, Company filed Schedule 12 —Power Purchases From and Sales to Cogenerators and Small Power Producers. This new proposed schedule was intended to be a voluntary rate schedule applying to cus-

tomers with generating facilities designated as new capacity as defined by 18 C.F.R. 292.304(b)(1).

A public hearing was held before Stewart E. Farrar, Hearing Examiner, on January 26 and 27, 1981, in the Commission's Courtroom, Jefferson Building, Richmond, Virginia. Counsel appearing were: Evans B. Brasfield, Esquire, Richard D. Gary, Esquire, and Douglas M. Palais, Esquire, for Company; Walter A. Marston, Jr., Esquire, and Sally Y. Wood, Esquire, for the Virginia Hydro Power Association; A. C. Epps, Esquire, and Charles F. Midkiff, Esquire, for the Virginia Committee for Fair Utility Rates; Eric M. Page, Esquire, for the Division of Consumer Council, Office of the Attorney General; Patricia M. Schwarzschild, Esquire, for Westvaco; and Donald G. Owens, Esquire, for the Commission. Six interveners appeared at the hearing.

On February 5, 1981, Company filed revised schedules, testimony, and exhibits for the purpose of correcting its earlier filing. Public notice, a public hearing, and consideration by the Commission of these revised schedules became unnecessary because of findings made by the Commission based on the evidence received in the January 26 and 27, 1981, public hearing.

On March 16, 1981, the Hearing Examiner filed his report. Subsequent to that date, Company, the Attorney General, Westvaco, Virginia Hydro Power Association, and Continental Forest Industries filed exceptions to the report.

On June 18, 1981, the Commission issued an Interim Order in this proceeding which contained the following findings:

(1) That each Qualifying Facility ("QF") with a design capacity exceeding 100 kw should negotiate the terms of its sale of electricity with Company and that the Commission will stand ready to arbitrate in the event that an agreement cannot be reached;

(2) That a single cogeneration schedule should be established for QFs having a design capacity of 100 kw or less, and that no distinction should be made between "old" and "new" capacity under such schedule;

(3) That Company's cogeneration schedule should provide that each QF has the option of either a simultaneous purchase and sale transaction or the sale only of its excess power; selection of such option shall be expressed in its contract and shall be for a period of not less than one year;

(4) That Company's cogeneration schedule should provide that those QFs willing to forego any capacity payments have the option to use only a time-differentiated kilowatt hour meter for measuring purchases of energy by the utility;

(5) That Company's cogeneration schedule should provide that those QFs who are willing to forego any capacity payments and are willing to be paid for all energy at off-peak rates should have the option to use only a standard single register kilowatt hour meter to measure energy purchased by the utility;

(6) That Company's cogeneration schedule should state that those customers desiring to provide power without reimbursement to Company are allowed to do so; in such instances, Company should only require the installation of a detent to prevent the customer's meter from running in reverse;

(7) That Company should define interconnection costs in its tariff as such costs are defined by FERC Rule, 18 CFR § 292.101(7), and that such costs should be repaid at the time of installation or over a period of up to 3 years, at the option of the QF, or over such longer period as may be mutually agreeable to the parties;

(8) That, in cases in which QFs pay interconnection costs over a period of time, Company should be allowed

to collect interest, the rate of such interest not to exceed the cost of Company's most recent issue of long term debt;

(9) That, in the event that any QF chooses to repay interconnection costs over a period of years, Company may require security for repayment;

(10) That Company's delineation of peak and off-peak periods is reasonable for the purpose of this proceeding;

(11) That Company's cogeneration schedule should provide that the payment of capacity credits will commence at the beginning of each contract term, and should be based upon the best available evidence at that time (such capacity credits may be revised on an annual basis);

(12) That the criteria for payment of capacity credits in Company's schedule should be expanded to include those found in FERC Rule § 292.304(e)(2)(vi) and (vii); that capacity credits should be available to QFs of any size or configuration which are willing to contract to supply capacity, and that Company's proposed capacity credits are reasonable;

(13) That Company should recalculate its avoided energy costs in accordance with the suggestions in Mr. Wittine's testimony;

(14) That Company's proposal to discount avoided costs for administrative expenses and unknown costs cannot be justified on the present record;

(15) That Company's proposal to include customer charges cannot be justified on the present record;

(16) That new notice and an additional hearing is required before this Commission can determine the reasonableness of Company's most recently proposed avoided costs;

(17) That Company's cogeneration schedule should provide that QFs are able to purchase power at any applicable retail rate;

(18) That Company should revise its cogeneration schedules in accordance with the findings herein and its most recent calculation of avoided costs, and that, during the period between the date of this order and any final determination regarding cogeneration schedules, that Company should negotiate temporary agreements with cogenerators that would be covered by such schedule; in the event that any agreements cannot be reached, the Commission stands ready to arbitrate differences;

(19) That Company should submit data to the Commission as recommended by Staff witness Wittine;

(20) That the findings made herein are limited to the record developed in this case.

In the June 18, 1981, Interim Order, the Commission ordered Company to file tariffs on or before July 1, 1981, in accordance with the findings listed above. The Commission also ordered Company to file the following data with the Commission on or before March 1 of each year beginning March 1, 1982, (such data to cover the 12 months ending the previous December 31):

The name and location of each QF interconnected with Company;

The design capacity of each QF;

The amount of energy purchased from each QF;

The amount of energy sold to each QF;

Copies of any contracts entered into between Company and QFs;

Avoided costs data of the type required by 18 CFR § 292.302.

The July 1, 1981, date for filing revised tariffs was later extended by Commission order dated June 26, 1981. Company filed a proposed Schedule 19 designed to replace its previously proposed Schedules 10 and 12 on August 14, 1981.

On December 8, 1981, the Commission filed an order setting a public hearing to be held on February 26, 1982, and requiring additional public notice.

The public hearing on February 26, 1982, was presided over by Stewart E. Farrar, Hearing Examiner. Counsel appearing were: Richard D. Gary, Esquire, and Douglas M. Palais, Esquire, for Company; A. C. Epps, Esquire, for the Virginia Committee for Fair Utility Rates; Stephen H. Watts, II, Esquire and John J. Carrara, Esquire, for Westvaco; Eric M. Page, Esquire, for the Division of Consumer Counsel, Office of the Attorney General; and Donald G. Owens, Esquire, for the Commission. Four intervenors testified at the hearing.

On April 19, 1982, the Hearing Examiner filed his report. The Hearing Examiner found that the proposed Schedule 19 complied with the Commission's June 18, 1981, Interim Order and that, subject to one qualification, Schedule 19 presented a just and reasonable method of regulating the purchases by Company of electrical energy from qualifying cogenerators and small power producers operating facilities with designed capacities of 100 kw or less. The reason for the Hearing Examiner's qualification of his approval concerned Company's charges for interconnection costs. The Interim Order of June 18, 1981, specified that the cost of interconnecting qualifying facilities with the system grid could be repaid at the time of installation, or over a period of up to three years, at the option of the qualifying facility, or over longer periods if mutually agreeable. The Order permitted reasonable interest and security for repayment to be required from those electing to spread payments over time.

Company incorporated these provisions in its tariff, Paragraph V(B) of Schedule 19, but also established a monthly charge equal to 0.75 percent of the cost of the required installation. (The tariff provides that Company will be the owner of all such facilities.) Such recurring charge would be paid by the customer whether its interconnection costs were paid immediately or over a period of years.

A Company witness testified that this monthly charge was intended to cover the operation and maintenance costs of the facilities in question, as well as the amortized cost of eventually replacing the equipment. The Hearing Examiner noted that it appeared somewhat inconsistent that the customer would have to pay the full costs of installing such equipment initially, and then immediately begin paying a fractional portion of such costs with his very next monthly bill. The Examiner suggested that a more uniform method would be to charge the customer for the costs of installation initially, and then to assess him for the full cost of any replacement facilities, if and when needed. The monthly charge would then cover only insurance, property taxes, and operation and maintenance of the facilities.

Although the Hearing Examiner noted that he was willing to recommend approval of Schedule 19 as proposed because he considered the above issue to be a rather minor one and because the proposed tariff does follow the practice established in Company's general terms and conditions, the Hearing Examiner asked Company to respond to his suggestion if it had serious objections to the proposed alternative.

Company filed a response to the Hearing Examiner's Report on May 4, 1982. In its response Company, after noting that both approaches to payment for interconnection costs have merit, suggested that, "as a third alternative, it may be appropriate to give each qualifying facility the option of paying a monthly charge which includes the

cost of eventual replacement or a monthly charge which does not include such cost." If the latter alternative is chosen, the qualifying facility would be responsible for the full cost of replacement of interconnection facilities at the time such replacement is required. Company also suggested that, if this third alternative is adopted by the Commission, the option should be a one-time option selected at the outset of construction of interconnection facilities, and should be binding on all future owners and operators of the qualifying facility.

NOW, THE COMMISSION, after consideration of the evidence presented in this proceeding, is of the opinion and finds:

(1) That the documents filed in Case Nos. PUE800082 and PUE800083 should be incorporated into the record of this proceeding;

(2) That each Qualifying Facility ("QF") with a design capacity exceeding 100 kw should negotiate the terms of its sale of electricity with Company and that the Commission will stand ready to arbitrate in the event that an agreement cannot be reached;

(3) That, in view of the cost of the facilities required for cogeneration, we believe Company's original proposal for assessing a monthly charge for the eventual replacement of interconnection facilities is consistent with the goal of encouraging cogeneration and, limited solely to that specific type of facilities, Vepco's proposed monthly assessment should be approved;

(4) That Company's proposed tariff Schedule 19 is a just and reasonable method of regulating the purchase by Company of electrical energy from qualifying cogenerators and small power producers operating facilities with design capacities of 100 kw or less; and,

(5) That the subject matter of proposed tariff Schedules 10 and 12 and of proposed paragraphs "C" and

"D" of Rider I are covered by tariff Schedule 19 or concern qualifying facilities with a design capacity exceeding 100 kw.

Accordingly, IT IS ORDERED:

(1) That Case Nos. PUE800082 and PUE800083 be, and hereby are, consolidated with the instant proceeding and all documents filed in Case Nos. PUE800082 and PUE800083 be transferred accordingly;

(2) That Company's tariff Schedule 19 be, and hereby is, approved for service rendered on and after the date of this order;

(3) That Company shall file the following data with the Commission on or before March 1 of each year (such data to cover the 12 months ending the previous December 31);

The name and location of each QF interconnected with Company;

The design capacity of each QF;

The amount of energy purchased from each QF;

The amount of energy sold to each QF;

Copies of any contracts entered into between Company and QFs;

Avoided costs data of the type required by 18 CFR § 292.302;

(4) That, there being nothing further to come before the Commission, the case be removed from the docket and the papers placed in the file for ended causes.

APPENDIX M

Final Order and Order Denying Petition for Reconsideration of the Virginia State Corporation Commission (November 15, 1985; December 6, 1985)

Case No. PUE830067
November 15, 1985

APPLICATION OF
VIRGINIA ELECTRIC AND POWER COMPANY

To revise Rate Schedule 19—Power Purchases from Cogeneration and Small Power Production Qualifying Facilities

FINAL ORDER

The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted by Congress to encourage conservation and efficient generation of electricity. Title II of that Act required the Federal Energy Regulatory Commission (FERC) to promulgate rules necessary to encourage cogeneration and small power production. As the United States Supreme Court observed in Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742, 72 L. Ed.2d 532, 102 S. Ct. 2126 (1982) and American Paper Institute, Inc. v. American Electric Power Service Corporation, 461 U.S. 402, 76 L. Ed.2d 22, 103 S. Ct. 1921 (1983), Congress believed that the development of cogeneration and small power production would reduce the demand for traditional fossil fuels. The FERC promulgated the required rules and thereby provided each state regulatory body a general framework within which the state authority was required to implement the PURPA mandate. The FERC rules afforded state commissions wide latitude in implementing the statutory requirements. A state commission could issue regulations,

resolve disputes on a case by case basis, or take any other action which was reasonably designed to give effect to the FERC regulations and PURPA.

As part of that general framework, the FERC provided that electric utilities must pay new qualifying facilities (QFs) an amount equal to the full avoided costs for the power sold by the QF. Although that standard appears clear enough, the calculation of those avoided costs can be the source of significant controversy, as demonstrated by this proceeding.

In Virginia the Commission determined that it was most appropriate to implement PURPA and the FERC regulations for each utility on a company by company basis. The Commission further determined that any QF with a design capacity exceeding 100 kw would very probably be a large concern with sufficient bargaining power to effectively negotiate the terms of its sale of electricity to the utility company. Therefore, the Commission determined that the terms, conditions and payment levels approved by the Commission for each utility should be applicable only to small QFs with a design capacity of 100 kw or less. The Commission, however, did offer to arbitrate whenever the large qualifying facility and the electric utility could not reach an agreement.

On January 11, 1983, in Case No. PUE800102, the Commission approved initial energy and capacity payments which it determined were reasonable for Virginia Electric and Power Company (Vepco) to pay small qualifying cogenerators and small power producers selling power to Vepco.

By letter dated October 27, 1983, Vepco was directed to update and file new rates which it proposed to pay QFs for purchased power based on current projections of its avoided costs. On December 1, 1983, Vepco filed its application and supporting testimony requesting a reduction in the energy and capacity payments it was re-

quired to pay to QFs. Vepco also requested approval of standard contracts for new QFs with a design capacity of less than 1,000 kw and a second standard contract for QFs with a design capacity of over 1,000 kw, as well as modification of the applicability of Vepco's Schedule 19 which currently reflects the terms, conditions, and avoided cost rates applicable to QFs with a design capacity of less than 100 kw.

Pursuant to the Commission's direction, Vepco revised its application on January 30, 1984, to base its proposed energy payments on projected avoided energy costs for the period of April 1, 1984, through March 31, 1985, and to base capacity payments on 1984 dollars, rather than 1983 dollars. Vepco's revised proposal was for a reduction in its time differentiated energy payment from 5.203 cents per on-peak kwh to 3.968 cents per on-peak kwh. It proposed to purchase non-time differentiated power on the same basis as off-peak power, 2.304 cents per kwh, a reduction from 3.132 cents per off-peak kwh. Vepco also proposed to change capacity payments. Prior to its filing, its capacity payments were .803 cents per on-peak kwh of dependable capacity for purchases with a contract term of less than five years and 1.253 cents per on-peak kwh for purchases with a contract term of five years or longer. Vepco proposed a graduated payment plan for capacity equal to $32.50 per kw per year or .833 cents per on-peak kwh for short term purchases with contract terms of nine years or less. For long term purchases with contract terms over nine years Vepco proposed to make capacity payments equal to the average of $32.50 per kw for each of the first nine years and $78.25 per kw for each additional year, with each year adjusted for the change in the GNP implicit price deflator during the previous year.

Vepco subsequently amended its proposal. By the conclusion of the hearing Vepco proposed on-peak energy payments of 4.109 cents per kwh and off-peak energy

payments of 2.477 cents per kwh. Its final proposal for capacity payments remained the same as described above.

Beginning on June 11, 1984, a public hearing before a Hearing Examiner was held. Counsel entering an appearance in this proceeding were: Richard D. Gary, Esquire, and Laurence Skinner, Esquire, for Vepco; Edward L. Flippen, Esquire, and John Carrara, Esquire, for Stone Container Corporation and Westvaco Corporation, Protestants; Eric M. Page, Esquire, Glenn J. Berger, Esquire, and Leslie J. Goldman, Esquire, for Union Camp Corporation, Protestant; A. C. Epps, Esquire, for the Virginia Committee for Fair Utility Rates, Protestant; Charles G. Flinn, Esquire, for Arlington County, Protestant; Cyril D. Calley, Esquire, for the City of Alexandria, Protestant; Daniel I. Prywes, Esquire, and Mark T. Gergen, Esquire, for Philip Morris, Inc., Protestant; Jim L. Chinn, Esquire, for the City of Richmond, Protestant; James C. Dimitri, Esquire, on behalf of the Office of the Attorney General, Division of Consumer Counsel; and Kenworth E. Lion, Jr., Esquire, Counsel to the Staff. Eighteen public interveners appeared and made statements.

On August 9, 1985, Senior Hearing Examiner Russell W. Cunningham issued his report and recommendations in this proceeding.

Parties' Exceptions and Comments to the Hearing Examiner's Report were filed on September 6, 1985.

The development of cogeneration and small power production in Virginia must be encouraged, and this Commission intends to do so. Such development has this Commission's full support for a number of persuasive reasons. Cogenerators can use fuel to produce steam for both their traditional industrial processes and to produce electricity. The extra cost to generate such electricity is obviously lower than the cost of generating electricity alone. Cogeneration is an economic and efficient use of

this nation's energy resources. It is also in the national public interest to decrease our reliance on scarce fossil fuels.

Similarly, a small power producer can make electricity from renewable resources. In Virginia, we have seen a particular interest in the use of water, wood chips, and waste resources. Again, this type of electric generation is economic and results in decreased reliance on traditional fuels.

There are many other direct and indirect benefits which inure to utilities such as Vepco, the ratepayer and the public at large from the encouragement of cogeneration and small power production. Such generation may enable the utility to defer investment in large generation units and thereby minimize the burden of utility financing. Moreover, small additional increments of power supply may also help the utilities more closely match their supply with the demand for electricity. Further, many small decentralized units will help insulate the utility and its ratepayers from major disruptive outages as may occur with a few large centralized generating units. Clearly, cogeneration and small power production are in the public interest.

The record amassed in this case is extensive. Numerous complex issues were raised and addressed. After reviewing the entire record, we have disposed of those issues as set out in the findings and conclusions in the remainder of this order. We believe the results we have reached here will make it clear that cogeneration and small power production facilities are welcome in Virginia and that this Commission fully supports the underlying concepts and intends to see that the development of those facilities is strongly encouraged in this state.

For example, we concur with the Hearing Examiner's recommendation that the use of standard contracts for both large and small QFs is not in the public interest and should be rejected. It was emphasized at the hear-

ing that each QF has unique characteristics which could make certain contract terms more important to one facility than another. Therefore, it is important for the Commission to maintain the requisite flexibility to allow larger QFs to negotiate the terms of their contracts to sell power to Vepco. Applicability of Vepco's Schedule 19 will therefore continue to be limited to small QFs with a design capacity of 100 kw or less. Standard contracts will not be approved for large QFs.

We disagree with the Hearing Examiner's recommendation that cogeneration contracts filed with the Commission should be held in camera. In orders filed on April 12 and April 22, 1983, in Case No. PUE830017, we denied a request by Vepco to make QF contracts unavailable to the public. We have re-examined our previous holding in light of the arguments received herein and continue to believe that it is in the public interest for QF contracts to be open for inspection by interested persons. We, therefore, adhere to our previous ruling.

In addition, for the purpose of Schedule 19 and for application to the small QFs covered thereby, "old" QFs should continue to receive full avoided cost payments. However, once again Vepco may negotiate other terms or payments with large QFs constructed prior to the enactment of PURPA.

In its application, Vepco proposed a new provision to Schedule 19 which would require the installation of telemetering equipment on all cogeneration and small power production facilities. It is unreasonable to require such equipment to be installed on the small facilities covered by Schedule 19. Vepco's proposal to incorporate that requirement is therefore rejected.

One of the most highly litigated issues in this proceeding was the appropriate methodology for determining Vepco's avoided energy costs. More particularly, several Protestants in this case raised serious questions on the use, input to and the accuracy of PROMOD. Vepco's

production costing simulation computer model. It is a well-established principle that a utility carries the burden of proving that the relief it requests in regulatory proceedings is reasonable and justified. In this case, Vepco's proposed rates were based to a large extent on the use of PROMOD, and we agree with the Protestants that such a computer program must be shown to be appropriate for the use to which it is put. The program should also be shown to produce valid results, based on suitable and reasonable inputs and assumptions, before it can form the basis of proof in a proceeding such as this. This record, however, reveals significant problems of proof with regard to this computer model which played such a principal role in deriving avoided energy costs. Vepco apparently input actual historical data in only one PROMOD run, which assumed QFs to be present on the system, in an attempt to validate the avoided energy cost calculations. Such minimal efforts do not constitute adequate validation. The case for the use of PROMOD in the determination of acceptability reliable avoided costs has not yet been established to the satisfaction of the Commission.

The Commission believes that a cooperative effort among Staff, Vepco and QFs can best develop the most appropriate method of determining avoided costs. This is particularly true inasmuch as we realize that, whatever the Commission's pronouncements on the subject, the matter will continue to remain controversial until the parties most immediately concerned, the utilities and the QFs, become satisfied that the process is reasonable and produces fair results. However, too much time has already elapsed in this proceeding to allow such a task force to conduct its work prior to our determination here of the reasonable level of payments which should be paid to QFs. Nevertheless, such a task force should be established and the consensus of the group presented in Vepco's next case. We are hopeful that the task force will be able to develop and propose, among other things, an

appropriate methodology for determining avoided energy costs which will be satisfactory to all. This methodology may or may not entail the continued use of PROMOD; however, for the purposes of this case there is no alternative to PROMOD offered in the record. The avoided energy cost calculations of 4.109 cents per on-peak kwh and 2.477 cents per off-peak kwh will therefore be used as the starting point in the development of energy payments for this proceeding. Vepco must, however, understand that our use of PROMOD for this case does not mean that the Commission finds that it has been sufficiently validated or that it represents the best approach to the derivation of avoided energy payments to QFs.

It is true that PROMOD has been used for years in Vepco fuel factor proceedings. However, there is a correction mechanism in the Fuel Factor to prevent over- or under-recovery by the utility. No such mechanism is included in the calculation of payments to QFs. That fact, alone, is sufficient reason why the inputs and calculations of PROMOD should be more carefully reviewed in cogeneration proceedings, and it is particularly important that the validity of computer models used in the process be clearly demonstrated.

Moreover, the Commission notes the discrepancy between the energy payments to QFs which Vepco proposed for the 1984-85 Fuel Factor and those calculated in this case. Both the fuel factor and the current projections of QF avoided cost rates were filed with the Commission on the same day. It would appear that the same inputs and data should be used in both proceedings. No explanation for the discrepancy was offered by Vepco. Hereafter, Vepco is expected to make consistent calculations in both the fuel factor and QF filings.

The FERC regulations very clearly provide the QF with the option of selling electricity to the utility at an avoided cost rate based on projections of avoided costs at the time the contract is executed or at the time the

power is actually delivered. Such an option is not only reasonable, but it is mandated by the FERC rules. To facilitate the availability of this option, it shall be incorporated into Schedule 19. To avoid encumbering the Schedule with all the alternative sets of projections available, Schedule 19, itself, should simply state that these two options exist, and the projected energy cost for contract terms of 5, 10, 15, 20, 25 and 30 years should be filed as an attachment to Schedule 19.

Vepco proposed to pay the off-peak energy rate for non-time differentiated purchases. Continued use of the weighted average costs calculated using on-peak and off-peak energy rates more accurately reflects the avoided cost of non-time differentiated power purchases from QFs. Therefore, Vepco's proposal is rejected and the starting point for calculating the appropriate payment for non-time differentiated purchases should be 3.204 cents per kwh.

Operating and maintenance costs should be included in the avoided energy cost calculation. Although average O&M costs may provide the easiest approach to the derivation of that energy related cost, the development of incremental O&M costs which was proposed by Protestant Union Camp more closely comports with the goal of developing payments based on the costs which would have been incurred by Vepco but for the presence of QFs on its system. That calculation in the proceeding must be updated, however, and the appropriate additional factor for avoided O&M costs in this case is 0.2131 cents per kwh.[1]

Amounts related to transmission line losses should also be factored into avoided energy cost calculations. It would be preferable to calculate this adjustment on a facility by facility basis, but for the purposes of Schedule

---

[1] See attached Schedule A for derivation of avoided O&M costs factor.

19 we will approve continued use of average transmission line losses. The appropriate component to be added to Schedule 19 energy payments is 0.275 cents per on-peak kwh and 0.166 cents per off-peak kwh.[2] For non-time differentiated purchases the weighted average of 0.214 cents per kwh should be factored into the total payment level.

In its application, Vepco proposed several changes to its capacity payments. It sought to increase the contract term necessary to receive long term capacity payments from five years to nine years. However, the record indicates that Vepco can alter its generation mix within a five year period; therefore, the five year term will be retained. Long term capacity payments will continue to be available to any QF which commits to a contract term of five years or more.

Vepco further proposed a change in the methodology of calculating avoided capacity payments. The existing methodology uses projected booked capacity costs to derive the capacity payments. Vepco's proposed short term capacity payments were based on six months of the Hoosier purchased power related costs. It proposed long term capacity payments based on a 750 MW coal fired generating unit projected to come on line in 1992. Too many problems with Vepco's new methodology were left unanswered in this proceeding. Therefore, we will adjust the previously approved capacity payment levels, which were based on 1981 data, for the change in GNP implicit price deflator from 1981 to 1984.

We further conclude that it is unreasonable to hold the QF to a reliability standard which Vepco itself has not come close to achieving. The Hearing Examiner's recommendation to compute the per kwh capacity payment to

---

[2] The transmission line loss factor was calculated in accord with Staff's recommendation in this case, by multiplying the on-peak and off-peak energy payments of 4.109 cents and 2.477 cents, respectively, by 6.682%.

QFs by multiplying the dependable capacity rating by the average availability of Vepco's own generation is reasonable and will be adopted. The reliability multiplier which would require QFs to be available with the same degree of reliability as Vepco's own generation in order to receive full capacity payments is 1.25. As thus calculated, capacity payments available to QFs under Schedule 19 will be 1.281 cents per on-peak kwh for short term purchases and 2.00 cents per on-peak kwh for long term purchases.

At this point we have discussed and resolved several issues which must be taken into account in developing avoided cost payments to QFs. Many of these issues, such as avoided energy and capacity costs, and adjustments for operation and maintenance and transmission loss factors, are costs internalized by the utility, and can be studied using the characteristics of that utility system, projections of its future operations, and the like. Other factors which make cogeneration and small power production facilities beneficial and in the public interest are more intangible however, and the associated costs which can be avoided are societal and environmental in nature. Such costs are not borne directly by the utility but by the public as a whole.

We have previously alluded to a number of these factors, and now note several that are required to be taken into account by the FERC rules. One is a reduction in the use of fossil fuels,[3] which saves money, conserves scarce resources, and lessens environmental pollution. Another is the possible deferral of major capacity additions by utilities,[4] which not only is financially advantageous to the utility but also conserves the real estate and other material and human resources which go into building and operating a major plant. Also of importance are

---

[3] 18 CFR § 292.304(e)(3).

[4] Ibid.

the shorter construction lead times and smaller additions to capacity which are possible with QFs.[5] The inability to respond quickly to small changes in demand caused by the long planning and construction times for major utility plants imposes many costs on society which are not paid by the utility, but which should be addressed in fixing avoided cost rates.

There are also enormous benefits to system reliability inherent in the prospect of having many small dispersed QFs throughout a state or region supplying the same amount of power as a single large utility plant, but without the catastrophic results possible should that single plant suffer an outage.[6]

It is thus important that factors such as the foregoing be considered in developing avoided cost rates. It is not to be expected, however, that such intangible benefits can be priced with mathematical precision and, therefore, it is not surprising that no attempt was made by the parties in this case to quantify their value. This fact does not relieve the Commission of its responsibility under the law to give reasonable weight to these matters. This task requires the exercise of our judgment and discretion, bearing in mind the mandate of PURPA that cogeneration and small power production is to be encouraged. We believe that the best way to accomplish this in the present case is to increase the avoided energy costs payments for both on- and off-peak periods by 15%. Thus, the rates for energy under Schedule 19 will be 4.725 cents per on-peak kwh, 2.849 cents per off-peak kwh and 3.685 cents per kwh for non-time differentiated purchases.

Above all, it must be emphasized that we recognize the unique characteristics of each QF. Consequently, we continue to encourage Vepco to negotiate contracts with each QF, giving due consideration to those characteristics

---

[5] 18 CFR § 292.304(e)(2)(vii).

[6] 18 CFR § 292.304(e)(2)(vi) Sch.

and the potential benefits which can result from cogeneration and small power production. As always, the Commisison stands ready to arbitrate specific contractual differences between the parties.

NOW, THE COMMISSION, upon consideration of the record in this proceeding, the Hearing Examiner's Report, the exceptions and comments filed by the parties to that Report, and the applicable law, is of the opinion and finds:

(1) That Vepco's proposal for standard contracts for all QFs is not in the public interest and is rejected;

(2) That all contracts executed by Vepco with QFs shall continue to be filed with the Commission and shall remain available for public inspection;

(3) That it is reasonable for Schedule 19 to remain applicable to both old and new QFs with a design capacity of 100 kw or less;

(4) That the proposal to incorporate a requirement for telemetering equipment as a provision in Schedule 19 is rejected;

(5) That Schedule 19 must be revised to provide QFs the option of contracting for payments based on projected avoided energy costs either at the time the contract is executed or at the time power is delivered;

(6) That is reasonable to use PROMOD to calculate total avoided production costs to develop a portion of payments for purposes of this proceeding. However, it is in the best interests of Vepco, QFs and the ratepayers that a cooperative task force be formed to investigate and make recommendations to the Commission for the most appropriate methodology to calculate avoided costs in future proceedings;

(7) That, in recognition of the various intangible societal and environmental benefits of cogeneration and small power production, it is proper to increase Vepco's

final proposed avoided energy costs payments for both on- and off-peak periods under Schedule 19 by a factor of 15%;

(8) That Vepco's avoided energy costs, plus the intangible considerations discussed above, support energy payments, exclusive of the O&M costs adjustment and the transmission line loss adjustment, of 4.725 cents per on-peak kwh and 2.849 cents per off-peak kwh;

(9) That the weighted average rate of 3.685 cents per kwh calculated using both on-peak and off-peak energy rates reasonably reflects the avoided cost of a non-time differentiated purchase;

(10) That operating and maintenance costs and transmission line losses should be included in the calculation of energy payments for Schedule 19 purposes. The incremental system O&M cost is 0.2131 cents per kwh. Average transmission line losses shall also be applied to Schedule 19 energy payments. That additional component is 0.275 cents per on-peak kwh and 0.166 cents per off-peak kwh, or 0.214 cents per kwh for non-time differentiated purchases;

(11) That it is proper to offer long term capacity payments to a QF which executes a contract with a term in excess of five years;

(12) That it is not reasonable to require QFs to be available 100% of on-peak hours in order to receive full capacity payments. It is, however, reasonable to hold QFs to the same reliability standard at which Vepco operates;

(13) That under Schedule 19 capacity payments should be 1.281 cents per on-peak kwh for short term power purchases (less than five year contract terms) and 2.00 cents per on-peak kwh for long term purchases to be adjusted each year for the change in the GNP implicit price deflator during the previous year; and

(14) That Vepco has underpaid QFs during the interim period and should, therefore, make additional payments to QFs for the period from April 1, 1984 to the present.

ACCORDINGLY, IT IS ORDERED:

(1) That Vepco shall file its revised Schedule 19 on or before November 29, 1985, to be effective on April 1, 1984, in accordance with the above findings;

(2) That, on or before December 20, 1985, Vepco shall make additional payments, with interest, to compensate QFs for the underpayments made by the application of the interim rates which became effective for purchases from QFs on and after April 1, 1984, to the extent that the interim payments were less than the payments which would have been made by the application of the permanent rates to be filed in compliance with this order;

(3) That interest shall be computed from the date payment is due until the date additional payments are made at an average prime rate for each calendar quarter. The applicable average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate values published in the Federal Reserve Bulletin, or in the Federal Reserve's "Selected Interest Rates" (Statistical Release G.13), for the three months of the preceding calendar quarter. The interest required to be paid shall be compounded quarterly;

(4) That, on or before December 30, 1985, Vepco shall file with the Commission's Staff a document showing that all additional payments have been properly made pursuant to this Final Order;

(5) That Staff from the Divisions of Energy Regulation and Economic Research and Development shall coordinate a task force of Vepco and QF representatives to develop an acceptable methodology for calculating avoided costs in the future; and

(6) That there appearing to be nothing further to come before the Commission in this proceeding, this case shall be removed from the docket and the papers placed in the file for ended causes.

Commissioner Elizabeth B. Lacy did not participate in this proceeding.

Schedule A

O & M COSTS FACTOR
DERIVATION

Resource	GWH	Percent	Average Variable O&M Cost cents per kwh	Average Variable O&M Cost cents per kwh
Nuclear	38.0	4.8%	0.0	0.0
Fossil	605.8	75.8	0.1480 [1]	0.1122
Combustion Turbines	27.4	3.4	2.968 [2]	0.1009
Other	127.8	16.0	0.0	0.0
Total	799.0	100%	3.115	0.2131

[1] $28,113,047 ÷ 18,995,854,000 kwh = .0014799 (.1480¢ per kwh)

[2] $1,164,652 ÷ 39,236,000 kwh = .02968 (2.968¢ per kwh)

Case No. PUE830067
December 6, 1985

APPLICATION OF
VIRGINIA ELECTRIC AND POWER COMPANY

To revise Rate Schedule 19—Power Purchases from Cogeneration and Small Power Production Qualifying Facilities

ORDER DENYING PETITION
FOR RECONSIDERATION

On November 15, 1985, the Commission issued its Final Order in this case which, among other things, revised the rates Virginia Electric and Power Company (Vepco or Company) is required to pay qualifying cogeneration and small power production facilities under Schedule 19 of its tariffs.

On November 25, 1985, Vepco filed a Petition for Reconsideration of that Final Order. Vepco requested reconsideration of findings made on the following issues: the necessity to offer long term energy rates, the required level of energy rate payments, and the appropriateness of the application of a reliability multiplier to determine reasonable capacity payments. Vepco further requested the Commission to make clear that the Commission is not required to pay QFs more than Company's avoided capacity costs per kw if the QF unit is more reliable than Company's own generation. Another issue raised in the Petition focuses on the appropriateness of the use of PROMOD for the determination of voided energy costs. Finally, Vepco sought reconsideration of the method used in deriving the adjustment to Schedule 19 for avoided line losses.

In view of the importance of this case, we have very carefully considered the points raised in Vepco's Petition for Reconsideration. After again reviewing the record,

we have concluded that there is no reason to modify our previous decision in the case, except for one point to be mentioned below.

Our examination of Vepco's Petition, however, does lead us to believe that the Commission may have misinterpreted the basic thrust and intention of the subject order. We, therefore, find it desirable to revisit and amplify certain aspects of that order.

First, and foremost, we did not hold, nor did we intend to suggest, that any QF is to be paid more than full avoided costs, for any reason. Company's contrary impressions are in error.

It is true, of course, that the final payments proposed by Vepco to capture full avoided costs were not adopted by the Commission; we decided that higher rate levels were necessary to meet that standard. In reaching that decision, we were careful, as mentioned in our order, to take into account every facet of avoided costs specified in the FERC regulations. However, the mere fact that the Company's position was rejected does not validate, for example, the argument in its Petition that the required payments to QFs will thus be at "115% of full avoided costs." [1]

In the first place, Vepco was not the only party in the case to suggest certain rate levels to meet the federal standards. Stone Container witness Shanker, for example, testified that the calculation of avoided energy costs should include certain adjustments which would result in an energy payment for on-peak periods in the range of 5.4 to 5.5 cents per kwh, disregarding additions for transmission line losses and operation and maintenance expenses. Also, as we noted in the November 15th order, Vepco's originally proposed rates in this case differed from its projected rates which were filed the same day

---

[1] Vepco, Petition for Reconsideration, p. 6.

in its 1984-85 Fuel Factor proceeding. Those Fuel Factor projections for on- peak and off-peak avoided energy costs were 4.67 and 2.62 cents per kwh, respectively. The level of avoided energy cost payments, prior to adjustment for line losses and O&M expenses, which the Commission adopted in this case—4.725 and 2.849 cents per kwh, on-peak and off-peak—thus fit well within the range of rates proposed in this record, and only slightly exceed Vepco's own numbers from its Fuel Factor filing.

It bears repeating that the Commission's holdings on rate levels were intended to match, not exceed, full avoided costs. Further, the Commisison fully recognizes that the methodology it chose in this proceeding to satisfy that standard may well not be the ultimate answer to the problem. We fully expect to reexamine this methodology in future cases. As we said in our order, it is also expected that the parties most concerned with this process, the utility and the QFs, will conduct immediate and extensive negotiations, in conjunction with our Staff, which will produce a more refined and improved method for capturing every aspect of full avoided costs. It is anticipated that the results of these negotiations will be acceptable to all parties and, when presented to the Commission, can be determined to be in the public interest and, thus, approved. We believe the foregoing to be the best way to eliminate the substantial controversy and uncertainty over the methodologies, rate levels, payment options, etc., which permeated this case.

The Commission also believes, however, that the methodology adopted in our recent order was reasonable and fully justified, and that it will serve well until a replacement is developed and approved. The Commission looks forward to considering other ways of meeting the federal mandate under which it operates in this area.

We noted above a need for clarifying one point in the order of November 15. It relates to Vepco's concern

(11) What rights, if any, should Virginia Power have to purchase the Facility?

WHEREFORE, UCS petitions the Commission to institute an arbitration proceeding.

Respectfully submitted,

ULTRA COGEN SYSTEMS, INC.

By /s/ Edward L. Flippen
Counsel

James C. Roberts
Edward L. Flippen
Deborah V. Ellenberg
Carolin D. Bakewell
Mays & Valentine
P. O. Box 1122
Richmond, Virginia 23208

Charles E. Schwenck
David J. Evans
Pillsbury, Madison & Sutro
Suite 1100
1667 K Street, N.W.
Washington, DC 20006

Dated: November 12, 1987

(Appendices Omitted)

APPENDIX C

Opinion and Final Order of the Virginia State Corporation (February 13, 1990)

Re Doswell Limited Partnership

Case No. PUE890068

Virginia State Corporation Commission
February 13, 1990

Opinion, Harwood, Commissioner:

OPINION AND FINAL ORDER

On September 25, 1989, Doswell Limited Partnership ("Doswell"), an independent power producer ("IPP"), filed an application with supporting prepared testimony and exhibits requesting the Commission's approval of Doswell's proposed construction of a 650 megawatt ("MW") combined-cycle generating plant to be located in Hanover County, Virginia. The applicant sought a certificate of public convenience and necessity, pursuant to Virginia Code § 56-265.2, and pursuant to Virginia Code § 56-234.3 which requires the company to satisfy the Commission following a public hearing, that ". . . the proposed improvements are necessary to enable the public utility to furnish reasonably adequate service and facilities at reasonable and just rates."

On October 3, 1989, the Commission issued an order directing Doswell to publish notice of its application and setting a procedural schedule. The application raises issues of first impression for this Commission concerning our jurisdiction over IPPs. Accordingly, we identified certain legal issues to be briefed

by Doswell and the Commission Staff, which briefs were filed on November 3, 1989. The required public hearing was held on December 7, 1989.

At the outset, it must be observed that Doswell has no certificated service territory and seeks none. As it stands, Doswell has no service obligations to Virginia customers. Its generating output will be sold exclusively to the Virginia Electric and Power Company ("Virginia Power") for resale. For this reason it is clear that the Commission must analyze the application in terms of Virginia Power's duty to provide reliable service to its customers at "reasonable and just rates."

Although this is the first application filed with the Commission for approval of an IPP facility, third-party generation is not new to us. Cogeneration and small power production have been steadily growing in the Commonwealth since the passage of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.* (1978) ("PURPA"). We have encouraged that development primarily because of the conservation objectives underlying PURPA. Facilities qualifying for construction under PURPA do not file with this Commission for construction and operating authority. IPPs, however, such as Doswell, are not afforded federal exemption from state regulation.

I. LIMITED PARTNERSHIP ORGANIZATION

Doswell is a limited partnership organized under the laws of the Commonwealth of Virginia. The sole general partner of the limited partnership is Doswell I, Inc., a Delaware corporation and a wholly-owned subsidiary of Diamond Energy, Inc. ("Diamond"). Diamond is a wholly-owned subsidiary of Mitsubishi Corporation. A second wholly-owned subsidiary of Diamond, Doswell II, Inc., is the sole limited partner of the limited partnership. Doswell II, Inc., is also a Delaware corporation. Doswell intends to sell limited partnership interests to a number of different entities and

eventually remove Doswell II, Inc. as a limited partner. Doswell, as a successor in interest to Intercontinental Energy Corporation ("IEC"), is a party to two power purchase and operating agreements ("the agreements"), each dated June 22, 1987, with Virginia Power. At the hearing, Doswell indicated that it was in the process of negotiating changes to several provisions in the agreements.

The Virginia Constitution provides that "[n]o foreign corporation shall be authorized to carry on in this Commonwealth the business of, or exercise any of the powers or functions of a public service enterprise, . . . " Virginia Constitution Art. IX § 5. Virginia Code § 13.1-620(E) prohibits the Commission from issuing a certificate of incorporation "[i]f one or more of the purposes set forth in the articles of incorporation is to own, manage or control any plant or equipment within the Commonwealth . . . for the production of heat, light, power" unless the articles, ". . . expressly state that the corporation is to conduct business as a public service company." Consequently, a domestic public service corporation is the only *corporate entity* which can engage in a public utility activity in Virginia. Doswell, however, is not organized as a corporation, as are most public utilities in Virginia. It is a Virginia limited partnership, and the definitions of "company" in Virginia Code § 56-265.1(a) and "public utility" in Virginia Code § 56-265.1(b) explicitly permit partnerships to hold certificates of public convenience and necessity.

It is our opinion that the limited partnership in this case should be treated as a separate entity for purposes of the certification and approvals which it seeks. Under the common law aggregate rule, partnerships were not treated as legal entities apart from the individual partners. However, Virginia has adopted the Uniform Limited Partnership and Uniform Partnership Acts which recognize a partnership as a legal entity separate and apart from its partners. Virginia Code §§ 50-73.1, *et seq.* and 50-1 *et seq.* Notably, a partnership can hold title to property in its own name

and limit a partner's rights to possession of that property. Virginia Code §§ 50-8 and 50.25. Those property rights are analogous to a certificate of public convenience and necessity, which the Virginia Supreme Court has held to be a valuable property right. *Culpeper v. Virginia Electric and Power Company,* 215 Va. 189, 207 S.E.2d 864 (1974). The Virginia Code grants partnerships the right to carry on any trade or business as a separate legal entity, apart from the partners. Virginia Code §§ 50-6 and 50-73.9. In the course of conducting a business, a partnership can sue and be sued in its own name without joinder of the partners. Virginia Code § 50-8.1.

A partnership is a separate legal entity under these partnership laws, and the Utility Facilities Act expressly recognizes the right of a partnership to function as a public utility. Consequently, we recognize Doswell as the public utility which will own the generating unit, and conclude that the general and limited partners need not incorporate as public service corporations. However, the present general partner, and all such future partners, that are charged with managing the project, may have information that is vital for the Commission's ongoing regulation of the operation of the Doswell facility. Accordingly, we shall impose certain requirements upon the general partners, which will be discussed below.

II. COMMISSION JURISDICTION

Doswell asserts that because it will sell only wholesale electricity to Virginia Power, its rates and services are governed by Part II, Sections 205, 206, and 207 of the Federal Power Act (16 U.S.C. §§ 824d-f). The Federal Power Act, 16 U.S.C. § 824(b) and § 824d, provides that such wholesale rates are exclusively governed by the Federal Energy Regulatory Commission ("FERC"). Under the Federal Supremacy Clause of the U.S. Constitution (Article VI, cl. 2), states are pre-empted from modifying the rates established by FERC. Yet, such pre-emption

does not otherwise remove Doswell from this Commission's statutory authority.

Upon reflection, we believe it unnecessary, and potentially dangerous, to seek to determine in this order the full extent of our jurisdiction over the applicant pertaining to problems or situations which are not before us nor likely identifiable; we do not render advisory opinions. It is sufficient to state that we consider our jurisdiction to be coextensive with that over all other Virginia electric utilities except to the extent pre-empted by federal law.

While we recognize that Doswell's rates, *i.e.*, its contract with Virginia Power, are subject to the jurisdiction of the FERC, we are not precluded from this initial evaluation and adjudication of the viability and appropriateness of the Doswell project. To the extent that the FERC jurisdiction is hereafter modified, terminated, or waived, we would expect to assert our jurisdiction to the full extent provided by state law. Further, a Doswell witness stated that he could not guarantee that Doswell's organizational structure would not change. If such a change occurs, it could trigger our jurisdiction.

As noted at the beginning of this order, the proposed facility is not one intended to supply electricity at retail to the customers of a utility possessing a certificated territory served by necessary transmission and distribution lines. Rather, since it serves only Virginia Power with wholesale power, the findings necessary under both Code §§ 56-265.2 and 56-234.3 must be established by evidence of need, costs, reliability, and preferable alternatives as those justifying elements relate to Virginia Power. The authority vested in the Commission by Virginia Code § 56-234.3 incorporates both licensing and rate aspects and Doswell itself recognizes that it is a "utility subject to the jurisdiction of the State Corporation Commission." Although our exercise of rate jurisdiction over Doswell is pre-empted, we do have certificate or licensing jurisdiction. That statute then is applicable to IPP projects as it relates to certificate matters. The fact that we do no

now expect to regulate Doswell's rates is not dispositive of our obvious need, and statutory duty, to conduct without reservation the investigation and overview contemplated by both of the foregoing code sections.

In this regard, Doswell is in a similar position to Old Dominion Electric Cooperative ("ODEC"), which is solely a wholesale power supplier to various retail cooperatives, in that ODEC is not subject to our rate jurisdiction as it relates to "sales of energy at wholesale,. . ." Va. Code § 56-231.12.[4]

Nevertheless, ODEC was recently brought before the Commission on a rule to show cause, Case No. PUE890045, when it became common knowledge that it had contracted for construction of a major generating plant without having filed for approval of that facility under Va. Code § 56-234.3. In fact, in earlier meetings with our Staff, ODEC had contended that such approval was unnecessary, since the Commission had no authority over wholesale rates. That argument was not pressed at the hearing on the rule, however, and soon thereafter, ODEC filed the appropriate application in Case No. PUE890051. That case culminated in our order of December 28, 1989, approving the new plant under the above provision. We see no reason not to apply the same statute to Doswell's proposals.

The Commission has a vital, ongoing interest in the construction and cost of the Doswell facility. Since we do regulate the services and rates of Virginia Power, it should be obvious that we have concerns with Doswell's proposal similar to those we would have if it were a Virginia Power proposal.

Inefficient, wasteful construction practices, procedures, designs, planning, etc., may have an adverse effect on Virginia ratepayers regardless of who the nominal builder/owner may be.

---

[4] True, with ODEC, our lack of jurisdiction is due to state rather than federal law, contrary to Doswell, but otherwise the analogy is a close one.

By all means, our responsibilities under Virginia Code § 56-234.3 should be discharged to the fullest extent possible, consistent with federal pre-emption. This includes the possibility of the employment by the Commission, at Doswell's expense, of qualified persons to audit and investigate the project, as specifically provided in § 56-234.3.

We recognize that under Chapters 3 and 4 of Title 56, Code of Virginia, our duty to review and approve a utility's proposed issuance of securities and its agreements with affiliated interests is conditioned upon our coextensive duty to regulate the rates of that utility. In this case, although we have no immediate power to respond to Doswell's security issuances or to its dealings with affiliated interests, we have a vital concern in those subjects because of their potential involvement in future FERC proceedings of interest to this Commission.

Therefore, upon the granting of any certificate as herein requested, the certificate holder, together with all general partners of any partnership holding any interest in the certificate to the extent provided by statute, their successors and assigns, shall be subject to the applicable regulatory provisions of Title 56, 1950 Code of Virginia. Provided, however, for so long as the Commission is precluded by federal law from regulating the rates of the certificate holder, the certificate holder and its general partner shall be required only to file the following information:

(1) The issuance of stocks and stock certificates or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness and the creation of liens on any of the certificate holder's property within Virginia, as described in Virginia Code § 56-57, and amendments thereto, shall be accompanied by the filing with the Clerk of the Commission of a statement setting forth the amount, character, terms, and purposes of the stocks, stock certificates, or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness issued or assumed; and

(2) There shall be filed with the Clerk of the Commission copies of all contracts or arrangements described in Virginia Code § 56-77, and amendments thereto.

Our exercise of certificate jurisdiction will not impair FERC rate regulation. FERC's jurisdiction over licensing of power plants extends only to those entities enumerated under 16 U.S.C. § 797 *et seq.* Such entities do not include the type of facility Doswell proposes to construct. Moreover, Doswell recognized the proper exercise of jurisdiction by this Commission.

This Commission's exercise of jurisdiction over licensing and reporting requirements regarding an IPP is not pre-empted as long as our regulation does not frustrate federal law. *Hines v. Davidowitz,* 312 U.S. 52 (1941). With regard to the reporting requirements, 16 U.S.C. § 824(a) provides that federal regulation of electric utilities should not extend to those matters regulated by the states. It is specifically provided by 16 U.S.C. § 825(a) that the Act (16 U.S.C. §§ 791a *et seq.*) "shall not relieve any public utility from keeping any accounts, memoranda, or records which such public utility may be required to keep by or under authority of the laws of any state." In this case, clearly no conflict with federal law exists. Doswell has agreed to provide operating and technical records pursuant to our regulation. In addition, there is no indication in the record that state reporting requirements will frustrate federal law.

III. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

As a starting point in evaluating Doswell's application, the Staff considered the criteria established in Case No. PUE860058, *Application of Virginia Electric and Power Company* ("Chesterfield 7"), 1987 S.C.C. Ann. Rep. 262. In that Order, the Commission stated:

> Several factors must be demonstrated to the satisfaction of the Commission before it can properly approve any new construction. Among these factors are that the utility will have a need for additional power within the time frame contemplated; that its cost estimates, choice of technology, construction plans and proposed manner of carrying out the project are reasonable; and that there are no suitable alternatives to the proposed construction such as conservation and load management, upgrading existing units, or obtaining the necessary, power from resources other than the utility's own facilities.

Id. at 262.

The Staff determined that the above criteria did not fully cover the proposed construction. In order properly to review the project, the Staff found it necessary to examine the technical and financial viability of Doswell and the proposed project. The Commission is directed by statute to determine whether a certificate of public convenience and necessity is in the public interest. An IPP must show the need for the project and the technical and financial viability of the developer and the project to allow us to conclude that a certificate of public convenience and necessity is in the public interest.

The record reflects that Virginia Power has a need for capacity in the early 1990's. This need is increased by Virginia Power's recent change in its target reserve margin from 18.5% to 21%. The loss of capacity associated with the Doswell project would leave Virginia Power with a minimal allowance for further attrition of purchased power. Moreover, the witness from Virginia Power testified that the proposed Doswell facility is in an optimal location near a Virginia Power transmission line and the Richmond-Washington corridor.

The Staff reported that Doswell's anticipated contractual payments from Virginia Power, which are based on the avoided

costs of Chesterfield 7, are reasonable when compared to payments for power from similar projects. While Doswell will not receive revenues from steam sales (since it is not a cogeneration facility), it may experience certain economies of scale due to its size. There is no reason to believe that the costs of the project will become unreasonable because it is no longer a cogeneration facility.

Important to our determination of whether Doswell should receive Commission approval of its certificate request is whether Doswell has the technical and financial ability to construct and operate the plant. The record demonstrates that Doswell has made significant progress since it assumed the IEC contract in June 1989. It has issued a letter of intent to contract for construction of the facility on a turnkey basis with Fluor Daniel, Inc., a reputable engineering, construction, and planning contractor which has significant experience in the construction of power plants. Additionally, it has filed its contract with FERC to obtain approval of its contract rates with Virginia Power; it is gathering information to solicit an operations and maintenance contractor; and it has secured or is in the process of securing environmental permits. In fact, the project will use effluent from the Hanover County Waste Treatment Plant which will have a positive effect on the quality of water in the North Anna River system. Additionally, Diamond Energy is involved in the development of three other power projects. Its technical qualifications to undertake the project are adequate.

As to financial viability, the record shows that the developer, through the support of Mitsubishi Corporation, is a viable entity. This, of course, is important to investors. However, the nonrecourse nature of the contemplated financing requires us to consider the project's ability to be financed on a stand-alone basis. Doswell has issued its Project Information Memorandum outlining its need for financing, which it anticipates obtaining by March 1, 1990. Several major investors have expressed interest in financing the project. We are encouraged by the progress Doswell has made in obtaining financing, and we believe the record before us

provides reasonable assurance that the project can be adequately financed.

Doswell has taken steps to secure firm transportation and interruptible storage from Consolidated Natural Gas ("CNG") and has sought FERC approval. Furthermore, Doswell is also completing its negotiations with Virginia Natural Gas ("VNG") for a firm transportation and capacity contract.

Other aspects of Doswell's efforts also reflect that the project is viable. Doswell has provided security payments in advance of their due dates to Virginia Power, demonstrating its commitment to the project. Doswell is subject to the same liquidated damages as IEC for delays in meeting milestones set forth in the agreements. In order to secure timely performance, Doswell is negotiating provisions with its contractors for substantial liquidated damages for any delays or failures in performance.

The evidence reflects a need by Virginia Power for capacity in the early 1990's. The evidence further reflects that Doswell is assembling the necessary expertise to construct and operate the project, and that it is capable of attracting the necessary capital.

NOW, THE COMMISSION, upon consideration of the record in this proceeding and the applicable law, finds that:

(1) Doswell's proposed combined-cycle generating plant, to be located in Hanover County, Virginia, capable of producing approximately 650 MW of electricity, is necessary to meet Virginia Power's capacity needs. The Doswell facility should, therefore, be approved. Doswell shall keep this Commission apprised of changes, if any, to its purchased power agreements with Virginia Power.

(2) Doswell's construction of such facilities for use in public utility service is required by the public convenience and necessity,

pursuant to the provisions of Virginia Code § 56-234.3 and § 56-265.2.

(3) It is appropriate to impose certain conditions upon the issuance of the certificate in this case to assure that the Commission is kept apprised of the activities of the limited partnership and general partner. Accordingly,

IT IS ORDERED:

(1) That Doswell's proposed construction and operation of the combined-cycle facility is hereby approved under Virginia Code § 56-234.3, and a certificate of public convenience and necessity shall be issued therefor upon the filing of maps, pursuant to Virginia Code § 56-265.2, subject, however, to Doswell's filing with the Clerk of the Commission three (3) copies of the January 3, 1990, revised, executed power purchase and operating contract by and between Doswell and Virginia Power.

(2) That Doswell shall comply with any and all reporting requirements directed by the Commission related to the construction, operation, and technical aspects of the subject project, and shall not sell or transfer any of its utility assets or the certificate of public convenience and necessity without first seeking Commission approval;

(3) That the certificate holder, together with all general partners of any partnership holding any interest in the certificate to the extent provided by law, their successors and assigns, shall be subject to all of the regulatory provisions of Title 56 of the Virginia Code which are not pre-empted by federal law;

(4) Doswell shall file with the Clerk of the Commission, information, reports, and contracts as follows:

(a) The issuance of stocks and stock certificates or other evidences of interest or ownership, and bonds, notes, and other

evidences of indebtedness and the creation of liens on any of the certificate holder's property within Virginia, as described in Virginia Code § 56-57, and amendments thereto, shall be accompanied by the filing of a statement setting forth the amount, character, terms, and purposes of stocks, stock certificates, or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness issued or assumed;

(b) Copies of all contracts or arrangements, and amendments thereto, described in Virginia Code § 56-77;

(c) Three copies of any and all future contracts or arrangements, and amendments thereto, executed by and between Doswell and Virginia Power;

(d) Any and all information, reports, etc., related to its operations as requested by the Commission's Divisions of Energy Regulation, Economic Research and Development, and Accounting and Finance;

(e) The foregoing filing requirements shall be binding upon all successors and assigns of Doswell.

(5) And this cause is continued pending further Commission action.

ATTESTED COPIES hereof shall be sent to Laurence M. Hamric, Esquire, Robert E. Spicer, Jr., Esquire, Williams, Mullen, Christian and Dobbins, Two James Center, 1021 East Cary Street, P. O. Box 1320, Richmond, Virginia 23210-1320; and to the Commission's Divisions of Energy Regulation, Accounting and Finance, and Economic Research and Development.

(5)

Supreme Court, U.S.
FILED
JUL 28 1995
OFFICE OF THE CLERK

No. 94-1868

IN THE
Supreme Court of the United States
OCTOBER TERM, 1995

NORTH CAROLINA POWER,
Petitioner,
v.
STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

PETITIONER'S REPLY MEMORANDUM

EDWARD S. FINLEY, JR.*
JAMES L. HUNT
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

WILSON - EPES PRINTING CO., INC. - 789-0096 - WASHINGTON, D.C. 20001

BEST AVAILABLE COPY

10pp

TABLE OF AUTHORITIES

CASES

	Page
Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988)	2, 6, 8
Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986)	2, 6, 8

ADMINISTRATIVE DECISIONS

Orange and Rockland Utilities, Inc., 43 F.E.R.C. ¶ 61,067 (1988); *stayed*, 43 F.E.R.C. ¶ 61,547 (1988); *vacated*, 70 F.E.R.C. ¶ 61,014 (1995)	6, 7

REGULATIONS

18 C.F.R. § 292.304(d)(2)	3

IN THE

Supreme Court of the United States

OCTOBER TERM, 1995

No. 94-1868

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

PETITIONER'S REPLY MEMORANDUM

North Carolina, through its Attorney General and the Public Staff of the North Carolina Utilities Commission, advance three primary points in opposition to North Carolina Power's petition.

First, the Attorney General maintains that the North Carolina Utilities Commission simply was exercising the same delegated authority under PURPA in 1993 in establishing retail rates that the Virgina State Corporation Commission exercised in 1987 and 1988 when Virginia ordered Virginia Power to make a wholesale purchase of the Ultra Cogen power at $341 per kW.

Second, the Public Staff maintains that when Virginia ruled upon the Ultra Cogen petition, filed pursuant to FERC's rules, implementing PURPA, and resolved the dispute between the QF and the electric utility through interpretation of FERC's regulations, Virginia was estab-

lishing a price above $171 per kW based on Virginia law, not Federal law.

Third, the Public Staff argues that there are no trapped costs as proscribed by *Nantahala Power & Light Co. v. Thornburg* [1] and *Mississippi Power & Light Co. v. Mississippi ex rel. Moore* [2] when North Carolina prohibited North Carolina Power from recovering $1.39 million per year in wholesale costs. The Public Staff argues that the utility theoretically can recover these costs in a Virginia retail rate proceeding.

These three points are factually and legally insupportable and demonstrate why the petition for certiorari raises important Federal issues and should be granted.

A.

First, contrary to the Attorney General's assertion, North Carolina was not implementing PURPA when it prohibited North Carolina Power (the name under which Virginia Power operates in North Carolina) from recovering $1.39 million per year of wholesale costs in retail rates. As all parties acknowledge, North Carolina's decision did nothing to establish the wholesale price Virginia Power must pay Ultra Cogen and therefore was not a decision establishing a wholesale rate. As the NCUC stated: "[i]n making this decision, we recognize our obligation to encourage QFs, but that is not the issue here. The issue here is ascertaining reasonable operating expenses for purposes of setting just and reasonable [retail] rates in North Carolina." App. 74a. The Ultra Cogen wholesale costs are the operating expenses the NCUC examined in establishing the retail rates for North Carolina consumers. In contrast, Virginia's 1987 and 1988 decisions established the price of the wholesale power. Virginia was implementing PURPA; North Carolina was not.

---

[1] 476 U.S. 953 (1986).

[2] 487 U.S. 354 (1988).

B.

Secondly, the Public Staff suggests that to the extent a portion of the $341 per kW price of the wholesale power exceeded $171, the determination approving the excess was based on State law. Contrary to the Public Staff's position, the price Virginia required Virginia Power to pay the QF above $171 per kW was not based on Virginia authority. Under the Supremacy Clause and the Commerce Clause decisions of this Court, Virginia has no state authority to establish a wholesale rate. The rate was established wholly through a delegation of Federal authority. The difference between the $341 per kW Virginia required in 1988 and the ceiling of $171 per kW selected by North Carolina five years later arose because Virginia interpreted the pertinent FERC regulation, 18 C.F.R. § 292.304(d)(2) (1987), to require that Virginia Power's avoided costs be determined at November 12, 1987. Virginia determined that there were no competitive bids in existence on that date that could be used to determine avoided costs. Virginia determined that avoided costs could only be determined with reference to Virginia Power's Chesterfield 7 plant costs as projected on that date, not bids submitted by competing suppliers calculated through reference to Chesterfield 7 costs as a benchmark. Use of Chesterfield 7 costs to establish avoided costs under PURPA is through reference to projected costs at the time the QF's obligation to sell is fixed. The projected future costs will vary on the basis of both the method for determining the costs and the date on which the costs are projected.

North Carolina's utilities commission found only that Virginia's attempt to implement PURPA produced a cost that was unreasonable for retail ratemaking or resulted from an interpretation that was not mandated by PURPA. However, as the North Carolina Attorney General emphasizes, PURPA gives the States wide latitude in implementing the provisions of PURPA requiring them to resolve disputes over price between QFs and utilities, as

did Virginia here. Attorney General's Brief in Opposition, pp. 11-13.

Whether Virginia's implementing decisions are the same as North Carolina would have made, however, is immaterial for purposes of the issue raised in this petition. The question is whether the authority Virginia exercised in selecting a wholesale price was Federal authority under PURPA, thereby preempting North Carolina's actions, or was State authority under State police power. As Virginia was exercising Federal authority, North Carolina was precluded from making a collateral attack on the Federal decision in a retail proceeding.

PURPA cannot be read to impose a cap of $171 per kW for the Ultra Cogen power so that a price of $172 or higher ceases to be grounded on PURPA but instead may only be authorized on state authority.[3] Tellingly, the Public Staff argues that an appropriate price under PURPA was both $141 per kW and $171 per kW. However, the Public Staff's argument that any price in excess of $171 ceases to be authorized under PURPA is inconsistent with its argument that a *range* from $141 to $171 is permissible under PURPA.

In reality it is North Carolina's attempt to support the $171 per kW through reference to PURPA that must fail. North Carolina ignored FERC's mandatory regulations in selecting the $171 price. Rather than follow FERC's regulations, which Virginia interpreted to require avoided costs to be determined on November 12, 1987, North Carolina looked to "contemporaneous" points of measurement. According to the Attorney General, "contemporaneous" as used by North Carolina means an "average purchase rate for capacity from contracts entered as a result of competitive bids initiated *less than*

---

[3] It must be remembered that the $171 per kW is an average of prices, many of which are above $171. If $171 is the cap, approximately one half of the prices making up the average exceed the cap, none of which were deemed by North Carolina to be in excess of federally mandated avoided costs.

a year earlier in December 1986, and just *a few months later* in March 1988, as well as rates set by the North Carolina Commission for small projects at the time the Ultra Cogen petitions were filed." Attorney General's Brief in Opposition, p. 20 (emphasis added). These "contemporaneous" measurements are at odds with PURPA regulations that address the date on which the wholesale determination of avoided costs is to be made. As the Virginia arbitrator ruled, the results of the 1988 solicitation, used by the NCUC to set the retail rate, were not known when the Ultra Cogen price had to be set.

The Public Staff incorrectly argues that the NCUC compared the Ultra Cogen contracts with contemporaneous measures of avoided costs and concluded that the prices in the Ultra Cogen contracts exceeded Petitioner's avoided costs "at the time the arbitration petitions were filed." Public Staff's Brief in Opposition, p. 7. The Public Staff's reference to the appendix (p. 73a) does not support the argument that the NCUC sought to set a price at November 12, 1987. The North Carolina Attorney General more accurately recites the NCUC's actions:

> The North Carolina Commission compared the purchase price for Ultra Cogen capacity with other contemporaneous measures of avoided costs for Virginia Power, and found the Ultra Cogen price out of line.

Attorney General's Brief in Opposition, p. 7. As this description indicates, the NCUC was drawing comparisons without reference to FERC regulations.[4]

C.

Thirdly, the Public Staff argues for the first time that the North Carolina decision does not trap wholesale costs

---

[4] The Attorney General's accurate description of the NCUC's actions precluded the argument that is essential to the Public Staff's brief and the North Carolina Supreme Court's opinion that the $341 per kW Ultra Cogen price does not carry preemptive force because it is based on Virginia instead of Federal authority.

by preventing their recovery through retail rates because the wholesale costs North Carolina disallows can be recovered in a Virginia retail rate proceeding. This argument is premised on the assumption, refuted above, that the $1.39 million in wholesale expenses was authorized on the basis of Virginia state law. Moreover, in a Virginia retail rate proceeding, Virginia retail ratepayers plainly cannot be required to pay both for the Ultra Cogen power Virginia Power actually sells to these consumers and part of the Ultra Cogen power Virginia Power sells to North Carolina consumers. Even if the responsibility for paying for what North Carolina disallows could be shifted to Virginia consumers, North Carolina cannot force this result by unilaterally prohibiting the recovery of the wholesale costs in a retail rate case in North Carolina.

The remedy the Public Staff advocates is the very remedy this Court reversed in *Nantahala* and *Mississippi Power*. In *Nantahala* the intent of the ratemaking device North Carolina had employed was to shift responsibility for wholesale costs from the North Carolina retail ratepayers to the Tennessee consumer.[5] North Carolina has no jurisdiction to reallocate the cost of the Ultra Cogen wholesale power it disallows in retail ratemaking to Virginia. Only FERC could have the authority to impose the remedy North Carolina advocates. The only authority North Carolina cites as a basis for this remedy, *Orange & Rockland*, has been vacated by FERC. *Orange & Rockland Utilities, Inc.*, 70 FERC ¶ 61,014 (1995). Consequently, there is no authority for the position whatsoever.

Even if *Orange & Rockland* had not been vacated, the reallocation hypothetically addressed in that FERC order is not available in this case. Orange & Rockland, the entity that purchased power from a QF at prices in excess of avoided costs on the basis of New York law, supplies wholesale power to affiliated systems in other states pur-

[5] 476 U.S. at 959-961.

suant to wholesale power supply agreements under FERC's jurisdiction.[6] FERC suggested that, through exercise of its jurisdiction over these agreements, it could prevent the allocation of excess costs from Orange & Rockland, which operates in New York, to the other affiliates, which operate outside of New York. No such comparable inter-affiliate wholesale agreements exist in this case. Virginia Power is a single electric utility operating in two states. There are no wholesale transactions or agreements between Virginia Power's operating territory in Virginia and North Carolina, and therefore there are no agreements under which FERC could allocate wholesale costs.

Further, even if reallocation of the wholesale costs were an appropriate remedy, North Carolina's decision is still preempted because North Carolina failed to impose any such remedy. Instead, North Carolina unlawfully resorted to self help. North Carolina could have gone to the proper Federal authority to argue that the price of the wholesale power resold in North Carolina be reduced. Alternatively, North Carolina could have gone to FERC to request a reallocation of the power to another jurisdiction that could not deny recovery of the costs. North Carolina cannot unilaterally through its retail ratemaking prohibit recovery of Federally-approved wholesale costs.

CONCLUSION

The case raises important Federal issues regarding the authority of North Carolina to review a Federal wholesale order and "trap" wholesale electric costs in a retail rate proceeding. Virginia, in the exercise of unquestioned Federal jurisdiction, ordered Virginia Power to sign a contract with Ultra Cogen. A portion of the Ultra Cogen wholesale power is resold at retail in North Carolina. Virginia followed FERC regulations in resolving the dispute between Virginia Power and Ultra Cogen in estab-

---

[6] *Orange & Rockland Utilities, Inc.*, 43 FERC ¶ 61,067 at pp. 61,185-61,186.

lishing the wholesale price. Virginia earlier had expressly repudiated the concept of permitting a price to a QF in excess of avoided costs as defined by PURPA on the basis of State law.

Virginia has not done anything more than exercise its discretion, for which it is given wide latitude, under PURPA. The Virginia decision is a Federal one, not a State one. In contrast, it is impossible to read the NCUC decision and conclude that it is anything other than a State decision establishing retail rates. North Carolina is pre-empted under *Nantahala* and *Mississippi Power* from reviewing a previously determined Federal wholesale rate.

The Court should grant North Carolina Power's petition. The decision of the North Carolina Supreme Court raises substantial Federal issues and conflicts with the decisions of this Court requiring States to honor Federal decisions establishing wholesale electric rates.

Respectfully submitted,

EDWARD S. FINLEY, JR.*
JAMES L. HUNT
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

Supreme Court, U.S.
FILED
JAN 16 1996
CLERK

No. 94-1868

IN THE
Supreme Court of the United States
October Term, 1995

NORTH CAROLINA POWER,
Petitioner,
v.
STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of North Carolina

PETITIONER'S SUPPLEMENTAL BRIEF IN RESPONSE TO THE BRIEF FOR THE UNITED STATES AND THE FEDERAL ENERGY REGULATORY COMMISSION AS AMICI CURIAE

EDWARD S. FINLEY, JR.*
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

WILSON - EPES PRINTING CO., INC. - 789-0096 - WASHINGTON, D.C. 20001

TABLE OF AUTHORITIES

FEDERAL CASES	Page
FERC v. Mississippi, 456 U.S. 742 (1982)	6
Jersey Central Power & Light Co. v. Federal Power Comm'n, 319 U.S. 61 (1943)	4
Mississippi Power & Light Co. v. Mississippi ex rel Moore, 487 U.S. 354 (1988)	5, 6
Nantahala Power & Light Co. v. Thornburg, 476 U.S. 354 (1986)	5, 6
Public Utilities Comm'n of Rhode Island v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927)	4
FEDERAL STATUTES	
16 U.S.C. 824a-3	1
16 U.S.C. 824a-3(e)	2
18 CFR § 292.304(e)(2)(vii)	7
MISCELLANEOUS	
Conference Report No. 95-1292, p. 98 (Oct. 6, 1978)	2

IN THE

Supreme Court of the United States

October Term, 1995

No. 94-1868

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of North Carolina

PETITIONER'S SUPPLEMENTAL BRIEF IN RESPONSE TO THE BRIEF FOR THE UNITED STATES AND THE FEDERAL ENERGY REGULATORY COMMISSION AS AMICI CURIAE

A.

The United States argues in its Brief ("Brief") that a decision under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 824a-3, by one State establishing the wholesale rate an electric utility must pay to a Qualifying Facility ("QF") has no preemptive effect over state retail ratemaking in another State. In support of its argument, the United States interprets several sections of PURPA for the proposition that when a State exercises the ratemaking power delegated to it by PURPA and establises a wholesale rate for a multistate utility this rate is not binding upon any other State because each State "control(s) only the operations of utilities within its own borders." Brief at 14.

This interpretation by the United States raises several concerns. First, it compromises the primary goal of PURPA to encourage the development of alternative suppliers of electric energy. That encouragement is manifested by not only the favorable pricing provisions of PURPA but also its exemption of QFs from other State laws generally applicable to electric utilities.[1] In order to champion the development of QFs, Congress unburdened QFs from extensive State regulation.

> The conferees wish to make clear that cogeneration is to be encouraged under this section and therefore the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or small power producer's power should not be burdened by the same examination as are utility rate applications, but rather in a less burdensome manner. The establishment of utility type regulation over them would act as a significant disincentive to firms interested in cogeneration and small power production.

Conference Report No. 95-1292, p. 98 (Oct. 6, 1978).

The United States' proposed "solution" to the issues in dispute here is inconsistent with that expressed Congressional intent; the United States suggests that QFs attempting to sell power to a multistate electric company, such as Virginia Power, would need to obtain approval in *each* State thereby multiplying the regulatory oversight and discouraging their development:

> PURPA's statutory and regulatory structure does not appear to have created any significant problems for multistate utilities. Such utilities can avoid incurring costs that they cannot fully pass on by obtaining prior approval of wholesale prices from each jurisdiction in which power purchased from a QF will be sold.

Brief at 16. This proposed "solution" would have added significant costs and delay for Ultra Cogen and the doz-

---

[1] 16 U.S.C. 824a-3(e).

ens of other QFs now providing power to Virginia Power. More importantly in terms of national policy, it is unlikely that Congress would have meant this as the "solution" when viewed in the context of the many regional electric holding companies that serve customers in several states from a combined pool of electric resources.[2]

Next, the United States inappropriately minimizes the express delegation of federal authority over wholesale electric sales to the States. Prior to PURPA, States had no jurisdiction to interfere with wholesale electric rates, which were federally established and deemed to be in interstate commerce. Likewise, prior to PURPA, no State had any authority to set a wholesale rate. PURPA, however, authorized States to set wholesale rates for purchases by electric utilities from QFs. The Virginia State Corporation Commission ("VSCC" or "Virginia") thus acted to render a federal decision in setting the wholesale purchase price Virginia Power must pay for power from the Ultra Cogen units. As such, the VSCC's decision stands on the same legal ground as a decision by the Federal Energy Regulatory Commission ("FERC") in setting other wholesale rates.

B.

The United States states that PURPA only sets "broad federal parameters," leaving implementation largely to each State, with margins for disuniformity and experimentation. Brief at 14. While the United States is correct that PURPA contemplates leeway for the States in resolving disputes and in establishing avoided cost rates, that does not nullify the status of the actions by the State regulatory commissions. Thus, when Virginia set

---

[2] For example, American Electric Power ("AEP") has operating electric subsidiaries in Virginia, Indiana, Ohio, West Virginia, Kentucky and Michigan. Allegheny Power Systems ("APS") has operating electric subsidiaries in Virginia, Maryland, Ohio, Pennsylvania and West Virginia. Under the United States' suggested "solution," a QF desiring to sell electric power to AEP or APS, for example, would require approval in all of the States in which the holding company serves.

avoided cost rates for Ultra Cogen at $341 per kW for the first 15 years of a 25 year contract, Virginia was free to rely upon administratively determined avoided costs as projected on November 12, 1987 and was not bound to apply the different measure of avoided costs that North Carolina later determined to be appropriate.

PURPA's overall objective is to encourage cogeneration, and that blends with the continuing national objectives articulated prior to PURPA to encourage the free flow of wholesale power in interstate commerce without piecemeal regulation by each jurisdiction where the power is resold. These policies are not advanced by a regulatory scheme—advocated by the United States—where parts of a QF contract are regulated by one State through one rate and other parts of the contract are regulated by another State through a different rate. And nothing in PURPA remotely contemplates this type of fractured, piecemeal regulation of QF arrangements with a multistate electric utility.

The analysis of the United States focused almost exclusively on the provisions of PURPA. Equally important and relevant are the Federal Power Act and the decisions of this Court leading to the Act's passage. The Federal Power Act was passed to fill the regulatory gap created by the decisions of this Court holding that the States did not have jurisdiction over wholesale power transactions.[3] These decisions were in response to the chaos created within the wholesale power market when each State in which such power was resold asserted jurisdiction and sought to establish its own rate. Subsequently, the Federal Power Commission (now the FERC) was established and given exclusive jurisdiction over wholesale power transactions to bring order from such chaos.[4]

---

[3] *Public Utilities Comm'n of Rhode Island v. Attleboro Steam & Electric Co.*, 273 U.S. 83, 89-90 (1927).

[4] *Jersey Central Power & Light Co. v. Federal Power Comm'n*, 319 U.S. 61, 67-68 (1943).

In 1978 Congress carved out an exception to FERC's exclusive jurisdiction over wholesale rates when it passed PURPA and mandated that limited federal decision-making be entrusted again to the States. Absent any definitive guidance from Congress in PURPA, there is no reason to believe that the federal decision-making as to any one QF contract should be divided between several States as now advocated by the United States. Such a regulatory scheme can only lead to chaos again among the States, and, in this instance, chaos for QFs that were granted favored status under PURPA in order to relieve this type of extensive State regulation.

C.

The United States dismisses *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 354 (1986) and *Mississippi Power & Light Co. v. Mississippi ex rel Moore*, 487 U.S. 354 (1988) as inapplicable to this case because at issue here "are state determinations under PURPA, not federal determinations by FERC under the Federal Power Act." Brief at 15. This distinction, however, misses the point. *Nantahala* and *Mississippi Power* stand for the proposition that States cannot establish retail rates in conflict with federally established wholesale rates. Here, Virginia established QF wholesale rates in accordance with the federal power delegated to it under PURPA; therefore, applying the rationale of *Nantahala* and *Mississippi Power*, another State should not be able to establish conflicting or inconsistent retail rates. Put in the words of this Court, Virginia was using its "state adjudicatory machinery" to enforce the QF's federal right to sell power at wholesale to electric utilities:

> Any other conclusion [than that Mississippi has jurisdiction to implement Section 210 of PURPA] would allow the States to disregard both the pre-eminent position held by federal law throughout the Nation, . . . and the Congressional determination that the federal rights granted by PURPA can appropri-

ately be enforced through state adjudicatory machinery.[5]

Thus, *Nantahala* and *Mississippi Power* are directly on point. Here, Virginia was making a federal decision concerning the cost of wholesale power. It is the federal/wholesale nature of the transaction, prescribed by federal law, that triggers federal preemption of inconsistent State regulation by North Carolina.

Importantly, the substance of the North Carolina decision cannot be overlooked. North Carolina, through a State retail ratemaking decision, disallowed the recovery of $1.4 million per year of wholesale power costs. As such, these wholesale costs were trapped through State retail ratemaking, and Virginia Power was not allowed to collect that revenue. The State trapping of wholesale costs is the very event proscribed by *Nantahala* and *Mississippi Power*. Moreover, the State involvement in the ratemaking requirements of PURPA was designed to assure that an electric utility dealing—possibly reluctantly—with a QF would not be left with unrecoverable costs from purchasing QF power. The North Carolina decision creates exactly that result for Virginia Power.

D.

The United States asserts that at the time of the 1987 and 1988 VSCC decisions, Virginia had a policy of encouraging favorable consideration of local economic benefits resulting from a particular project and that the arbitrator took such policy into account by "requiring petitioner to contract with Ultra Cogen."[6] The United States'

---

[5] *FERC v. Mississippi*, 456 U.S. 742, 760-61 (1982).

[6] The United States asserts that Virginia relied upon intangible factors favorable to Virginia in determining that Virginia Power should contract to buy the power. The "local economic factors" the United States suggests the arbitrator "appears to have taken into account" are that the Ultra Cogen facilities "are coal-fired cogen-

citations to support this assertion are solely to the North Carolina Utilities Commission's ("NCUC") orders purporting to interpret Virginia policy, not directly to any specific Virginia policy pronouncement. Contrary to these North Carolina interpretations of the Virginia policy, the VSCC had articulated its policy to be to give reasonable weight to intangibles "bearing in mind the mandate of PURPA that cogeneration and small power production is to be encouraged." App. 224a. The VSCC policy was that "we did not hold, nor did we intend to suggest that any QF is to be paid more than full avoided cost for any reason." App. 230a. The VSCC stated that "its holdings on rate levels were intended to meet, not exceed, full avoided costs" (App. 231a) and that "no QF should receive more than full avoided costs." App. 232a. Nothing in the 1987 and 1988 VSCC Ultra Cogen orders conflicts with this policy.

The United States, however, suggests that it is unclear whether the VSCC based its decision requiring Virginia Power to pay Ultra Cogen $341 per kW exclusively on federal law and, therefore, this case is an inappropriate vehicle to resolve the federal preemption issue:

> To the extent that the Virginia arbitrator's decision may be ambiguous as to whether it actually exceeds PURPA's avoided-cost ceiling (based on state law) or whether it depends solely on federal law, that ambiguity might have been eliminated by the Virginia Supreme Court if petitioner had pursued an appeal of the VSCC's order adopting the arbitrator's determination.

---

eration facilities in lesser populated areas of the Commonwealth." App. 189a. These factors were considered to conform to earlier VSCC orders requiring the Commission to consider "system reliability inherent in the prospect of having many small dispersed QF's throughout the region" not a "single large utility plant." App. 224a. The basis for this requirement is FERC's own regulations, not State law. 18 CFR § 292.304(e)(2)(vii).

Brief at 17-18. But there is no ambiguity in the VSCC orders. The VSCC established the cost of $341 per kW through resort to the proxy of the Company's cost of its Chesterfield 7 plant, as projected on November 12, 1987, as allowed by PURPA. As noted above, the VSCC's calculation of avoided costs "were intended to meet, not exceed, full avoided costs." App. 231a. Thus, VSCC's order was based clearly on federal law.

E.

Virginia Power has taken every reasonable step required to comply with PURPA and to protect the often competing ratepayer and QF interests. Virginia Power argued before the VSCC that a lower federal avoided cost should be paid to Ultra Cogen and resisted before the VSCC Ultra Cogen's effort to base avoided costs on administratively determined procedures instead of competitive bids. When the VSCC rejected these good faith efforts through valid, lawful orders, Virginia Power promptly executed the contracts as ordered containing the terms required to permit the QF to build its projects. No appeal was taken because the VSCC had acted within its delegated federal authority over these rates.

The United States suggests, echoing the North Carolina interests, that Virginia Power was remiss in failing to appeal the VSCC orders and in not immediately filing its VSCC mandated contracts with the NCUC so that North Carolina could join in the appeal. The United States suggests that the appeal should have been based on an "ambiguity" as to whether the VSCC opinion was based on Virginia or federal law. Brief at 17-18. At the time of the VSCC decision, of course, no ambiguity existed; FERC itself had not come definitively to a conclusion on the issue of whether independent State authority existed to set a wholesale rate in the 1987-88 time frame.[7]

---

[7] *See* discussion, Brief for United States of January 1996, at 4-5.

If FERC was unsure on this issue, it is unlikely that an appeal to the Virginia Supreme Court would have removed the alleged ambiguity.

North Carolina requires executed QF contracts to be filed with the NCUC for informational purposes. Virginia Power had no contract with Ultra Cogen to file in North Carolina until the VSCC had dictated its terms. Filing in North Carolina of the VSCC mandated contract would have had no impact on this dispute. Likewise, Virginia Power may not be legitimately criticized for failing to "file papers" in North Carolina to notify the NCUC of the action the VSCC had undertaken. The VSCC proceedings were initiated against Virginia Power by the VSCC upon Ultra Cogen's petition, and Virginia Power was made a party despite its objections to the contracts. Virginia Power sought no relief as a respondent in the VSCC proceeding that conflicts with any North Carolina interest in any way.

CONCLUSION

No provision of PURPA suggests, much less requires, a result that permits North Carolina to ignore a federal/wholesale rate established for Ultra Cogen in Virginia. The United States' argument that a federal/wholesale rate is without effect beyond the boundaries of the State that sets that rate pursuant to PURPA-delegated authority competes directly with the overriding objectives of PURPA to encourage cogeneration and the national policy to remove restraints on the free flow of wholesale power in interstate commerce.

Virginia relied exclusively upon PURPA to establish avoided costs rates for Ultra Cogen. No State authority was asserted. North Carolina's collateral attack on that federal decision squarely raises the federal preemption issue Virginia Power asserts. The Court should review this issue on the merits.

Respectfully submitted,

EDWARD S. FINLEY, JR.*
HUNTON & WILLIAMS
One Hannover Square
Fayetteville Street Mall
Raleigh, NC 27601
(919) 899-3000

EDGAR M. ROACH, JR.
JAMES S. COPENHAVER
NORTH CAROLINA POWER
P.O. Box 26666
Richmond, VA 23261
(804) 771-3174

Counsel for
North Carolina Power

* Counsel of Record

Supreme Court, U.S.
FILED
JAN 3 1996
CLERK

No. 94-1868

In the Supreme Court of the United States

OCTOBER TERM, 1995

NORTH CAROLINA POWER, PETITIONER

v.

STATE OF NORTH CAROLINA *EX REL.*
UTILITIES COMMISSION

ON PETITION FOR A WRIT OF CERTIORARI TO THE SUPREME COURT OF NORTH CAROLINA

BRIEF FOR THE UNITED STATES AND THE FEDERAL ENERGY REGULATORY COMMISSION AS AMICI CURIAE

DREW S. DAYS, III
Solicitor General
EDWIN S. KNEEDLER
Deputy Solicitor General
CORNELIA T.L. PILLARD
Assistant to the Solicitor General
Department of Justice
Washington, D.C. 20530
(202) 514-2217

SUSAN TOMASKY
General Counsel
JEROME M. FEIT
Solicitor
TIMM L. ABENDROTH
Attorney
Federal Energy Regulatory Commission
Washington, D.C. 20426

QUESTIONS PRESENTED

1. Whether a State, in exercising its authority to set rates for retail sales of electric energy to consumers, is required by the Supremacy Clause to pass on to its consumers the full wholesale energy cost paid by a multistate utility, where that cost was set by another State, under the authority of Section 210 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a-3.

2. Whether the State's refusal to pass on to its consumers the entire wholesale energy costs paid by a multistate utility violates the Commerce Clause.

TABLE OF CONTENTS

	Page
Statement	1
Discussion	11
Conclusion	17

TABLE OF AUTHORITIES

Cases:

American Paper Inst., Inc. v. *American Elec. Power Service Corp.*, 461 U.S. 402 (1983)	3, 4
Arkansas Elec. Coop. v. *Arkansas Pub. Serv. Comm'n*, 461 U.S. 375 (1982)	11
Arkansas v. *Oklahoma*, 503 U.S. 91 (1992)	14
City of Milwaukee v. *Illinois*, 451 U.S. 304 (1987)	13
Connecticut Light & Power Co., 70 F.E.R.C. ¶ 61,012, reconsid. denied, 71 F.E.R.C. ¶ 61,035 (1995)	4, 5, 15
Consolidated Edison Co. of New York, Inc. v. *Public Serv. Comm'n*, 472 N.E. 2d 981 (N.Y. Ct. App. 1984), appeal dismissed, 470 U.S. 1075 (1985)	4
FERC v. *Mississippi*, 456 U.S. 742 (1982)	1-2, 2-3, 12
International Paper Co. v. *Ouellette*, 479 U.S. 481 (1987)	14
Mississippi Power & Light Co. v. *Mississippi ex rel. Moore*, 487 U.S. 354 (1988)	13
Nantahala Power & Light Co. v. *Thornburg*, 476 U.S. 953 (1986)	13
Northwest Cent. Pipeline v. *State Corp. Comm'n*, 489 U.S. 493 (1989)	11
Occidental Chem. Corp. v. *FERC*, 869 F.2d 127 (2d Cir. 1989)	5
Orange & Rockland Utils., Inc., 43 F.E.R.C. ¶ 61,067 (1988), stay granted, 43 F.E.R.C. ¶ 61,547, vacated for mootness, 70 F.E.R.C. ¶ 61,014 (1995), reconsid. denied, 71 F.E.R.C. ¶ 61,034 (1995)	4, 5
Pilot Life Ins., Co. v. *Dedeaux*, 481 U.S. 41 (1987)	11

Constitution, statutes and regulations:	Page
U.S. Const. Art. I, § 8, Cl. 3 (Commerce Clause)	10
Federal Power Act, 16 U.S.C. 791a *et seq.*	13
16 U.S.C. 796(18)(A)	2
Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, Tit. III, § 210, 92 Stat. 3144:	
§ 210, 16 U.S.C. 824a-3	1
§ 210(a), 16 U.S.C. 824a-3(a)	2
§ 210(b), 16 U.S.C. 824a-3(b)	2
§ 210(b)(1), 16 U.S.C. 824a-3(b)(1)	2
§ 210(d), 16 U.S.C. 824a-3(d)	2
§ 210(e), 16 U.S.C. 824a-3(e)	3, 12
§ 210(f)(1), 16 U.S.C. 824a-3(f)(1)	2, 12
§ 210(g), 16 U.S.C. 824a-3(g)	3
§ 210(h)(2), 16 U.S.C. 824a-3(h)(2)	16
18 C.F.R. 292.304	3
Va. Code Ann. § 12.1-39 (Mitchie 1995)	8
Miscellaneous:	
45 Fed. Reg. (1980):	
p. 12,214	4, 15
p. 12,221	4, 15
pp. 12,230-12,231	3, 9
p. 12,231	13
53 Fed. Reg. 24,099 (1988)	5
58 Fed. Reg. (1993):	
p. 51,777	14
p. 51,778	14
H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. (1978)	3

In the Supreme Court of the United States

OCTOBER TERM, 1995

No. 94-1868

NORTH CAROLINA POWER, PETITIONER

v.

STATE OF NORTH CAROLINA *EX REL.* UTILITIES COMMISSION

ON PETITION FOR A WRIT OF CERTIORARI TO THE SUPREME COURT OF NORTH CAROLINA

BRIEF FOR THE UNITED STATES AND THE FEDERAL ENERGY REGULATORY COMMISSION AS AMICI CURIAE

This brief is submitted in response to the Court's order inviting the Solicitor General to file a brief expressing the views of the United States.

STATEMENT

1. a. Congress enacted Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 824a-3, in response to the domestic energy crisis of the 1970s. Section 210 was designed "to encourage the development of cogeneration and small power production facilities," in order to decrease reliance on fossil fuels. *FERC*

v. *Mississippi*, 456 U.S. 742, 750 (1982).[1] Congress recognized that the reluctance of traditional electric utilities to purchase power from non-traditional facilities had been an obstacle to the development of those facilities. 456 U.S. at 750-751.

Section 210(a) of PURPA, 16 U.S.C. 824a-3(a), directs the Federal Energy Regulatory Commission (FERC) to promulgate rules to foster the development of small power production facilities, and specifically to require electric utilities to make wholesale purchases of electric energy from qualifying facilities, or "QFs." See *FERC* v. *Mississippi*, 456 U.S. at 751. PURPA further directs FERC to promulgate rules to ensure that the rates for such wholesale purchases are "just and reasonable" to the utility's consumers and "in the public interest," and that they do not discriminate against QFs. 16 U.S.C. 824a-3(b)(1). PURPA imposes a ceiling, however, to ensure that ratepayers will not be required by federal law to subsidize purchases mandated by PURPA: No FERC rule "shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy," 16 U.S.C. 824a-3(b)—*i.e.*, "the cost to the electric utility of the electric energy which, but for the purchase from [a QF], such utility would generate or purchase from another source." 16 U.S.C. 824-3(d).

PURPA relies substantially on the States for its implementation. Specifically, Section 210(f)(1) requires that, "each State regulatory authority shall * * * implement" the rules adopted by FERC "for each electric utility for which it has ratemaking authority." 16 U.S.C. 824a-3(f)(1); see generally *FERC* v. *Mississippi*, 456

---

[1] Cogeneration refers to the process of simultaneously producing electricity and thermal energy, such as heat or steam, usually at an industrial site. 16 U.S.C. 796(18)(A).

U.S. at 759-760; *id.* at 775 n.1 (O'Connor, J. concurring). FERC's rules establish only the basic regulatory framework, and "afford the State regulatory authorities * * * great latitude in determining the manner of implementation of the Commission's rules." 45 Fed. Reg. 12,230-12,231 (1980). "Thus, a state commission may comply with the statutory requirements by issuing regulations, by resolving disputes on a case-by-case basis, or by taking any other action reasonably designed to give effect to FERC's rules." *FERC* v. *Mississippi*, 456 U.S. at 751. Judicial review of state commissions' decisions under PURPA is generally limited to the state courts. 16 U.S.C. 824a-3(g); H.R. Conf. Rep. No. 1750, 95th Cong., 2d Sess. 84 (1978) ("The findings and determinations by the courts are reviewable under the substantive standards of review as established under State law.").

Congress in PURPA also recognized that federal and state utility regulations could impose financially and administratively burdensome obligations on QFs that might hinder their ability to participate in the wholesale market for electric power. PURPA Section 210(e), 16 U.S.C. 824a-3(e), thus authorizes FERC to prescribe rules exempting many cogeneration and small power facilities from state and federal regulation. That provision authorizes regulatory preemption of state law "in the traditional way." *FERC* v. *Mississippi*, 456 U.S. at 759.

b. FERC's regulations regarding prices for power purchases from QFs require utilities to buy electricity made available by QFs at the "full avoided cost." See 18 C.F.R. 292.304. FERC's full-avoided-cost rule was sustained in *American Paper Inst., Inc.* v. *American Elec. Power Service Corp.*, 461 U.S. 402, 412-418 (1983). The avoided-cost rule does not provide immediate savings to consumers, because it requires utilities to pay QFs the same rate they would otherwise pay for electric energy.

This Court held, however, that FERC reasonably placed greater emphasis on the need to maximize the incentives for development of small power production, to the long-term benefit of consumers and the Nation. *Id.* at 415-416.

Although full avoided cost is a ceiling on the wholesale price FERC may require a utility to pay a QF, until recently FERC did not state a clear position on whether States, under their own laws, can require purchases from QFs at prices exceeding the federal avoided-cost ceiling. In the preamble to FERC's regulation regarding avoided-cost rates for wholesale purchases from QFs, FERC suggested that the rates it prescribed under PURPA Section 210 were "subject to the statutory parameters," but that "the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies." 45 Fed. Reg. 12,214, 12,221 (1980). Such higher rates would "be based on State authority to establish such rates, and not on the Commission's rules." *Ibid.*; see, *e.g.*, *Consolidated Edison Co. of New York, Inc.* v. *Public Serv. Comm'n*, 472 N.E.2d 981 (N.Y. Ct. App. 1984), appeal dismissed, 470 U.S. 1075 (1985). In 1995, FERC clarified its position, partly in view of new policies in favor of competition, to hold that both PURPA and its implementing regulations bar the prescription of all QF wholesale rates that exceed avoided cost. *Connecticut Light & Power Co.*, 70 F.E.R.C. ¶ 61,012, reconsid. denied, 71 FERC ¶ 61,035 (1995), appeal pending *sub nom. Niagara Mohawk Power Corp.* v. *FERC*, Nos. 95-1222 & 95-1223 (D.C. Cir. filed Apr. 21, 1995).[2]

---

[2] On April 14, 1988, FERC initially ruled, prospectively, that States may not impose rates for purchases from QFs that exceed avoided cost, *Orange & Rockland Utils., Inc.*, 43 F.E.R.C. ¶ 61,067, reh'g denied, 43 F.E.R.C. ¶ 61,546 (1988). On June 16, 1988, however,

2. In December 1986, petitioner Virginia Electric and Power Company, a multistate electric utility operating in Virginia (as Virginia Power) and in North Carolina (as North Carolina Power, see Pet. ii), solicited bids from various QFs for electric generating capacity that petitioner projected it would need. That competitive bidding process had been approved by the Virginia State Corporation Commission (VSCC) as an acceptable means of complying with Section 210 of PURPA and establishing the avoided-cost price to be paid (based on the lowest acceptable bids) for QF-produced power purchased by Virginia Power. Pet. App. 167a-168a. Virginia Power employed a competitive solicitation procedure because it was receiving QF capacity offers that exceeded its projected power needs. *Id.* at 31a. The solicitation letter specified, as a benchmark for bidding, the capacity and energy charges projected for petitioner's planned gas-fired generating plant, Chesterfield Unit No. 7; petitioner received bids "right at the benchmark price." *Id.* at 73a, 141a.

FERC stayed its order pending judicial review, 43 F.E.R.C. ¶ 61,547 (1988), and the court of appeals subsequently dismissed the petitions for review, *Occidental Chem. Corp.* v. *FERC*, 869 F.2d 127, 129 (2d Cir. 1989). Because the April 14, 1988, order was prospective and was promptly stayed, it had no concrete effects. The *Orange & Rockland* proceeding has since been dismissed as moot, and the prior orders have been vacated. *Orange & Rockland Utils., Inc., et al.*, 70 F.E.R.C. ¶ 61,014, reconsid. denied, 71 F.E.R.C. ¶ 61,034 (1995), appeal pending *sub nom., Niagara Mohawk Power Corp.* v. *FERC, et al.*, N.D.N.Y. No. 95-CV-634 (filed May 11, 1995).

On June 27, 1988, FERC initiated rulemaking proceedings on the question whether it should codify the position expressed in the April 14, 1988, order. See 53 Fed. Reg. 24,099. That rulemaking was still pending when FERC ruled in 1995, in *Connecticut Light & Power Co.*, that States may not, even under their own authority, exceed the full avoided costs allowed under federal law.

Petitioner selected for negotiation ten projects from that 1986 solicitation, and, in June 1987, it contracted with seven of those projects. Pet. App. 31a. The average avoided cost of the six projects that ultimately came on line from the 1986 solicitation process for Virginia Power was $141/kW. *Id.* at 76a. One of the companies that participated in the 1986 solicitation, Ultra Cogen Systems (Ultra Cogen), submitted proposals that petitioner rejected because their price was too high. *Id.* at 31a. In 1988, petitioner again requested competitive bids from QFs, and it entered additional wholesale purchase contracts at an average price of $171/kW. *Id.* at 36a.

b. Meanwhile, after its bid responding to the 1986 solicitation was rejected, Ultra Cogen petitioned the VSCC in November 1987 for an order directing petitioner to contract with it to purchase power. Pet. App. 33a, 166a.[3] Ultra Cogen's petition specified that its proposed cogeneration project was "of critical importance" to the continued viability of a large industrial plant that had been operating in a rural Virginia community for 75 years, and to the economic health of that community. NCUC Public Staff Br. in Opp. App. 7a. Specifically, the petition stated that the cogeneration project would affect the plant's ability to continue to employ 1,200 people, and would result in an additional $60 million investment in the community. *Ibid.*[4] Faced with the VSCC arbitration, petitioner did not file

---

[3] Petitioner objected on the ground that the VSCC had approved the competitive bidding process under which petitioner rejected Ultra Cogen's bids. Pet. App. 34a, 173a.

[4] A January 29, 1988, policy statement by the VSCC specified that, in evaluating specific proposals from QFs, weight should be given to economic and societal benefits to the people of the Commonwealth of Virginia, including the use of Virginia fuels, labor and other state resources, and the benefits to industries and communities associated with particular projects. Pet. App. 33a.

any papers with the North Carolina Utilities Commission, notwithstanding the fact that North Carolina retail customers comprise a fraction of petitioner's customer base. Pet. App. 35a-36a.

The VSCC appointed an arbitrator to resolve Ultra Cogen's dispute with petitioner, and the arbitrator required petitioner to purchase power from Ultra Cogen. Pet. App. 169a-183a. The arbitrator evaluated Ultra Cogen's offer by reference to petitioner's avoided costs as of November 12, 1987, the date upon which Ultra Cogen filed its arbitration petition. *Id.* at 172a. He determined that avoided costs should be calculated based on petitioner's projected costs on that date of constructing and operating its planned Chesterfield 7 plant, "since that unit is intended to be the prototype of any new capacity to be built by the Company through the mid-1990's, and perhaps beyond." *Ibid.* The arbitrator rejected petitioner's contention that the results of its 1986 or 1988 competitive solicitations, rather than the Chesterfield 7 cost projections, should furnish the appropriate measure of avoided costs. *Id.* at 34a, 173a.

On May 27, 1988, the arbitrator directed the parties to negotiate 25-year contracts obligating petitioner to purchase power from Ultra Cogen at $341.23/kW for the first 15 years of operation, and at $189.70/kW for the last ten years. Pet. App. 179a. His order did not specify how he arrived at those figures under the methodology he had outlined. *Ibid.*[5] The arbitrator approved four identical agreements consistent with those terms, *id.* at 189a, all of which were for facilities located in Virginia, Pet. 11. The arbitrator specifically commented on the "unique circum-

---

[5] As noted above, the 1986 competitive solicitation, which was guided by Chesterfield 7 cost projections, yielded a price of $141/kW, and the 1988 competitive solicitation yielded a price of $171/kW.

stances of these proceedings (including that [the facilities funded by the contracts] are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." Pet. App. 189a.

The VSCC, in a two-sentence order, ratified and adopted the Arbitrator's Order on November 18, 1988. Pet. App. 191a-193a. VSCC decisions are directly appealable to the Virginia Supreme Court, Va. Code Section 12.1-39 (1995), but petitioner did not appeal the VSCC's order.

c. In 1992, petitioner applied to the North Carolina Utilities Commission (NCUC) to increase its rates for electric service to its North Carolina retail customers. That filing was the first notice the NCUC received of the VSCC arbitration and its results. Petitioner's application sought leave to allocate to its few ratepayers that reside in North Carolina a share of the cost of its Ultra Cogen contracts, at the rate set by the Virginia arbitrator and adopted by the VSCC. Petitioner thus sought to pass on to North Carolina ratepayers approximately $2.8 million of the total annual cost of $64 million for the Ultra Cogen contracts. Pet. App. 62a.

The NCUC's Public Staff recommended that petitioner's expenses recoverable in North Carolina be reduced by $1.39 million annually, to exclude what it considered to be costs exceeding full avoided costs. The $1.39 million figure was based on the difference between the Virginia arbitrator's $341/kW avoided-cost calculation for the Ultra Cogen projects, and a figure of $171/kW, which was the average cost of power for seven QF projects, selected by the 1988 competitive bidding process, for which petitioner had contracted at the time it signed the contract with Ultra Cogen. Pet. App. 65a-66a.

On February 26, 1993, the NCUC adopted the staff recommendation. Pet. App. 24a-139a. The NCUC noted that the cost of the Ultra Cogen projects was twice the

average cost of the projects resulting from petitioner's 1988 bid solicitation process. *Id.* at 65a-66a. The NCUC determined that the costs petitioner contracted to pay Ultra Cogen were unreasonable, and that it was not bound by the VSCC's decision with regard to the Ultra Cogen projects. *Id.* at 36a. The NCUC rejected petitioner's argument that the NCUC's own rate order was preempted by the VSCC decision. *Id.* at 68a. The NCUC instead noted that PURPA and FERC's regulations permit flexibility to the States in implementation and recognize that "economic and regulatory circumstances vary from State to State." *Id.* at 67a-68a (quoting 45 Fed. Reg. 12,230-12,231 (1980)). The NCUC further ruled that its own determination of avoided cost for the Ultra Cogen projects, based on the 1988 competitive bidding procedure followed in Virginia, was consistent with PURPA and FERC regulations. Pet. App. 69a.

The NCUC also concluded that some of the high cost of the Ultra Cogen contracts appeared to be based on state law rather than PURPA. It observed that "[w]hile PURPA and the FERC regulations do not allow rates greater than avoided costs, there may be a separate basis in state law or policy for such higher rates." Pet. App. 68a. The NCUC referred to the VSCC policy statement providing that, in evaluating QF proposals, favorable weight should be given to a proposed project's economic and societal benefits to Virginia industries and communities. *Id.* at 33a, 63a. The NCUC found it "clear that the arbitrator considered economic benefits unique to the State of Virginia in setting the [Ultra Cogen] capacity payments." *Id.* at 68a. The NCUC concluded that "[t]hese benefits flow to Virginia, not to North Carolina. For this reason, it may be reasonable for Virginians to pay * * * extra costs associated with the [Ultra Cogen] projects. But it is unreasonable for North Carolinians to pay such

extra costs, and our responsibility is to set fair and reasonable rates for North Carolina." *Id.* at 74a.

The NCUC also pointed out that petitioner had violated the terms of a 1987 NCUC Order implementing PURPA in North Carolina that required utilities to submit contracts with QFs to the NCUC upon their execution. Pet. App. 35a-36a, 60a-61a. It further noted that petitioner did not appeal the VSCC order to the Virginia Supreme Court. *Id.* at 65a.

d. The North Carolina Supreme Court affirmed. Pet. App. 1a-24a. It held that the NCUC's order did not violate PURPA "to the extent it only excludes the amount *above* avoided costs," *id.* at 6a, and found that the NCUC's measure of avoided cost, based on a competitive bidding process, was not unreasonable, and therefore did not violate PURPA, *id.* at 7a-9a. The court also held that the NCUC order did not violate the Commerce Clause. *Id.* at 10a-11a. It observed that "Congress has the power under the Commerce Clause to regulate the relationships between cogenerators and electric utilities in order to protect interstate commerce." *Id.* at 10a. Because the NCUC order was authorized under PURPA and FERC's regulations and "constitutes lawful retail ratemaking," the North Carolina Supreme Court concluded that it did not violate the Commerce Clause. *Id.* at 11a. Although the court acknowledged the burden on petitioner from differing avoided-cost determinations in different States, it found that burden to be "a necessary consequence of doing business in more than one state," and noted that petitioner had "accepted the risk" of not being able to recover excessive Ultra Cogen costs in North Carolina by failing to appeal the VSCC decision. *Ibid.*

Two justices dissented. Pet. App. 14a-21a. They would have concluded that the rate set by the VSCC was binding on the NCUC's retail ratemaking decisions.

DISCUSSION

The decision of the North Carolina Supreme Court is correct, and it does not conflict with any decision of this Court or of any federal court of appeals or state court of last resort. Moreover, this case would not in any event be an appropriate vehicle for consideration of the questions petitioner presents. Petitioner's preemption theory depends on its contention that the wholesale rate set by the Virginia State Corporation Commission (VSCC) was based solely on federal law. It appears, however, that in setting that rate, the VSCC arbitrator may have relied at least in part on state law. Review therefore is not warranted.

1. Petitioner contends (Pet. 16-28) that, under PURPA, the decision of the VSCC setting a wholesale rate for petitioner's purchase of power from Ultra Cogen in Virginia has preemptive force in retail ratemaking proceedings by the North Carolina Utilities Commission (NCUC) for North Carolina residents. Congressional intent is the touchstone of preemption analysis. See, *e.g.*, *Northwest Cent. Pipeline* v. *State Corp. Comm'n*, 489 U.S. 493, 509 (1989), *Pilot Life Ins. Co.* v. *Dedeaux*, 481 U.S. 41, 45 (1987). Petitioner's contention is not supported by the text, structure or purposes of PURPA.

The text of PURPA does not provide that one State's avoided-cost determinations have determinative force in another State. Rather, PURPA expressly recognizes the traditional limitations on each State's regulatory authority to activities within the State. It is a long-settled principle that state authority to regulate retail transactions in the sale of electricity "is one of the most important of the functions traditionally associated with the police power of the States." *Arkansas Elec. Coop.* v. *Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1982).

Against that backdrop, any congressional grant of authority to one State to preempt important aspects of retail ratemaking in another State must be clear. PURPA Section 210(f)(1), however, expressly confines a State's powers in implementing PURPA to those utilities over which "it has ratemaking authority." 16 U.S.C. 824a-3(f)(1). An individual State's "ratemaking authority" over a multistate utility is confined to the utility's operations within that State. The statutory text shows that Congress intended a state commission's actions under PURPA to control only the operations of utilities within its own borders. The text thus cuts against petitioner's assertion that the VSCC's avoided-cost determination controls the NCUC's decision making.

The conclusion that Congress did not intend to grant States preemptive authority in other States is reinforced by PURPA's express preemption provision, Section 210(e), 16 U.S.C. 824a-3(e), which authorizes FERC alone—and not individual States—to exempt qualified power facilities from "State laws and regulations." This Court has described that provision as preempting conflicting state law "in the traditional way." *FERC* v. *Mississippi*, 456 U.S. at 759. The existence of an express preemption provision granting preemptive authority exclusively to FERC undermines petitioner's contention that Congress in PURPA also intended implicitly to take the unprecedented step of vesting one State with federal preemptive power over its neighboring States.

PURPA's overall structure and purpose further reinforce the thrust of the plain language. PURPA's unique system of cooperative federalism—setting only broad federal parameters and leaving implementation largely to the separate regulatory and adjudicative processes of each State—contemplates a certain amount of disuniformity and experimentation from State to State.

Indeed, in its administration of PURPA, FERC has consistently afforded broad discretion to the States, recognizing that "economic and regulatory circumstances vary from State to State and utility to utility." 45 Fed. Reg. 12,231 (1980).

There is no basis to petitioner's assertion (Pet. 19-28) that the decision in this case is contrary to *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U.S. 354 (1988), and *Nantahala Power & Light Co.* v. *Thornburg*, 476 U.S. 953 (1986). Those cases involved not state determinations under PURPA, but federal determinations by FERC under the Federal Power Act (FPA), 16 U.S.C. 791a *et seq*. The FPA, unlike PURPA, does not rely upon state implementation and does not contemplate disuniformity among the States with respect to determinations under federal law. *Mississippi Power & Light* involved sales of electric power made pursuant to interaffiliate wholesale contracts among producing and operating subsidiaries of a multistate public utility holding company. Those sales were subject to FERC's jurisdiction under the FPA. Similarly, *Nantahala* involved purchases of wholesale power by affiliated utilities under contracts subject to FERC's FPA jurisdiction. Both cases recognized that FERC's exclusive authority over wholesale energy sales would be undermined if state retail rate decisions could effectively change the rates FERC set. Here, by contrast, it is the States' authority to implement PURPA, not the authority of FERC under the FPA, that is at issue.[6]

---

[6] Amicus Edison Electric Institute's reliance (EEI Br. at 6) on *City of Milwaukee* v. *Illinois*, 451 U.S. 304 (1987), for the proposition that Congress has implicitly delegated preemptive federal authority to States in other contexts is misplaced. The Court held in *City of Milwaukee* v. *Illinois* that the complaining downstream State lacked a federal common-law remedy to challenge a "source" State's implemen-

PURPA's statutory and regulatory structure does not appear to have created any significant problems for multi-state utilities. Such utilities can avoid incurring costs that they cannot fully pass on by obtaining prior approval of wholesale prices from each jurisdiction in which power purchased from a QF will be sold. Moreover, recent increased reliance on competitive rather than administrative methods for setting avoided costs, see 58 Fed. Reg. 51,777, 51,778 (1993), promises greater State-by-State uniformity in pricing and thus decreases the likelihood that the problem petitioner identifies will recur.[7]

Finally, there is no conflict among the courts of appeals or state courts of last resort on the issue in this case. Indeed, similar problems do not appear to have arisen elsewhere. Petitioner cites no case raising this issue before any state commission or federal or state court. In these circumstances, this Court's review is unwarranted.

2. This case is, in any event, an inappropriate vehicle for resolution of the questions petitioner presents. Petitioner's theory turns on its assertions that the VSCC rate determination was based exclusively on federal law. It appears, however, that the VSCC may have based its decision in part on state law.

---

tation of federal pollution standards because federal legislation provided an administrative remedy, which the downstream State failed to pursue. *Id.* at 326. As the Court explained in subsequent cases addressing disputes between source States and downstream States, see *Arkansas* v. *Oklahoma*, 503 U.S. 91, 102 (1992), and *International Paper Co.* v. *Ouellette*, 479 U.S. 481, 490-491 (1987), downstream States do not have authority to block permits issued by upstream States; rather, the affected downstream States' recourse is to the EPA.

[7] We agree with the NCUC (NCUC Public Staff Br. in Opp. 26-28) that no economic protectionism in violation of the Commerce Clause is implicated by the NCUC decision in this case.

At the time of the arbitration, FERC had not expressly clarified whether States, under the authority of their own laws, could require wholesale purchases from QFs at prices exceeding the federal avoided-cost ceiling. See 45 Fed. Reg. 12,214, 12,221 (1980); *Connecticut Light & Power Co.*, 70 F.E.R.C. ¶ 61,012, reconsid. denied, 71 F.E.R.C. ¶ 61,035 (1995), appeal pending *sub nom. Niagara Mohawk Power Corp.* v. *FERC*, Nos. 95-1222 & 95-1223 (D.C. Cir. filed Apr. 21, 1995). At that time, Virginia had a state policy of encouraging favorable consideration of local economic benefits resulting from particular QF projects, see Pet. App. 33a, 63a, and the VSCC arbitrator appears to have taken into account the asserted benefits to Virginia from requiring petitioner to contract with Ultra Cogen, *id.* at 68a. As the NCUC noted, if petitioner was required to pay a premium in order to produce economic benefits for the Commonwealth of Virginia, North Carolina ratepayers should not be required to subsidize those benefits. *Id.* at 74a.[8]

To the extent that the Virginia arbitrator's decision may be ambiguous as to whether it actually exceeds PURPA's avoided-cost ceiling (based on state law) or whether it depends solely on federal law, that ambiguity might have been eliminated by the Virginia Supreme Court if petitioner had pursued an appeal of the VSCC's order adopting the arbitrator's determination. Indeed, even if the arbitrator intended to rely exclusively on federal law and to comply with PURPA's avoided-cost ceiling, the prices the arbitrator ordered for the Ultra Cogen contracts appeared even to Virginia Power to be far out of line with contemporaneous PURPA prices for purchases from QFs. An appeal might have identified

---

[8] Even now, petitioner may be able to seek authority from the VSCC to recover the additional cost from Virginia ratepayers.

errors in the arbitrator's methodology and thereby ameliorated or cured the problem petitioner now faces.[9] Moreover, if petitioner had promptly notified the NCUC of the Ultra Cogen contracts, as it was required to do under the NCUC's 1987 order, see Pet. App. 35a-36a, 60a-61a, the NCUC could have intervened in such an appeal and sought clarification of the impact that local factors had on the VSCC's pricing decision or correction of the methodology upon which the arbitrator relied. In the absence of any such opportunity, the decision of the North Carolina Supreme Court declining to require the NCUC to pass on some of the Ultra Cogen costs to North Carolina ratepayers does not warrant further review.[10]

---

[9] We take no position on the question of what is the correct avoided-cost figure for the Ultra Cogen contracts, nor, contrary to petitioner's suggestion (Pet. 23 n.32) has FERC taken any position on the question in any of its rulings.

[10] Amicus EEI makes the misdirected suggestion (Amicus Br. 9-10) that the NCUC erred procedurally in this case by not requiring petitioner to request that FERC, under PURPA Section 210(h)(2), 16 U.S.C. 824a-3(h)(2), challenge the VSCC's avoided-cost decision (and require petitioner to sue in its own right if FERC declined to do so), and thereby create an opportunity for the NCUC to intervene to protect its interests. It was petitioner, not the NCUC, that omitted needed procedural steps. Petitioner's failure to notify the NCUC of the Virginia arbitration, and its failure to appeal the VSCC's decision, eliminated any opportunity for the NCUC to intervene or otherwise make its interests known, and perhaps to work out a resolution satisfactory to all interested parties, before the VSCC's decision became final and unappealable under applicable state procedures.

CONCLUSION

The petition for a writ of certiorari should be denied.

Respectfully submitted.

DREW S. DAYS, III
Solicitor General

EDWIN S. KNEEDLER
Deputy Solicitor General

CORNELIA T.L. PILLARD
Assistant to the Solicitor General

SUSAN TOMASKY
General Counsel

JEROME M. FEIT
Solicitor

TIMM L. ABENDROTH
Attorney

Federal Energy Regulatory Commission

JANUARY 1996

Supreme Court, U. S.
F I L E D
JUL 17 1995
CLERK

No. 94-1868

In the
Supreme Court of the United States
October Term, 1994

North Carolina Power,
Petitioner,

v.

State of North Carolina ex rel.
Utilities Commission,
Respondent.

Petition for a Writ of Certiorari to the Supreme Court of North Carolina

ATTORNEY GENERAL'S BRIEF IN OPPOSITION

MICHAEL F. EASLEY
North Carolina Attorney General

Margaret A. Force*, Assistant Attorney General

North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602-0629
(919)733-7214

**Counsel of Record*

QUESTIONS PRESENTED

1. Whether the Public Utility Regulatory Policies Act of 1978 authorizes the North Carolina Utilities Commission to examine the appropriate avoided cost rate for purchases from certain cogeneration facilities by Virginia Electric and Power Company, when the issue is first presented in North Carolina in the context of a retail rate case, or whether such an examination is preempted under the Supremacy Clause of the United States Constitution by an arbitrated determination of the purchase rate approved by the Virginia State Corporation Commission, in which the Virginia arbitrator did not consider alternative sources of purchased power in setting the Virginia rate.

2. Whether the North Carolina Utilities Commission is bound by the Commerce Clause of the United States Constitution to accept without examination a purchase rate set by an arbitrator for the Virginia State Corporation Commission for electricity purchases from cogeneration facilities by a utility subject to the ratemaking authority of both North Carolina and Virginia commissions where federal statute and rules require each state regulatory authority to implement federal rules governing such purchases.

This page intentionally left blank.

TABLE OF CONTENTS

QUESTIONS PRESENTED i

TABLE OF AUTHORITIES v

STATEMENT OF THE CASE 2

Introduction 2

Background 3

REASONS WHY THE WRIT SHOULD NOT BE GRANTED 9

I. THERE IS NOT A FEDERAL QUESTION OR CONFLICT AT ISSUE HERE: THE NORTH CAROLINA DECISION DOES NOT VIOLATE THE SUPREMACY CLAUSE. 9

A. NORTH CAROLINA ACTED UNDER PROPER AUTHORITY GRANTED IN PURPA AND FERC REGULATIONS AND ITS DECISION WAS NOT PRE-EMPTED BY A VIRGINIA CORPORATION COMMISSION DETERMINATION. 9

B. VIRGINIA HAS NOT RAISED A SUBSTANTIAL FEDERAL QUESTION AND THE NORTH CAROLINA DECISION DOES NOT CONFLICT WITH DECISIONS OF OTHER COURTS. 15

1. CONFLICT WITH VIRGINIA. 15

2. CONFLICTS WITH DECISIONS OF OTHER COURTS AND FERC. 15

3. CONFLICTS WITH DECISIONS OF THIS COURT. 16

4. DICTA IN DOSWELL. 18

5. USE OF APPROPRIATE DATE. 19

6. THE DUTIES TO ENCOURAGE COGENERATION AND PROTECT CONSUMERS. 20

II. NORTH CAROLINA'S DECISION DOES NOT VIOLATE INTERSTATE COMMERCE. 22

CONCLUSION 27

APPENDIX

Portions of the Preamble to 18 CFR Part 292 . . . . . 1a

TABLE OF AUTHORITIES

CASES

American Paper Inst. v. American Elec. Power Serv. Corp., 461 U.S. 402 (1983) 12

Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742 (1982) 11, 16, 17, 22, 23

Freehold Cogeneration Associates, L.P. v. Bd. of Regulatory Comm'rs of New Jersey, 44 F.3d 1178 (3rd Cir. 1995), *cert. pet. pending*, *New Jersey Division of Ratepayer Advocate v. Freehold Cogeneration Associates, L.P.*, Docket No. 94-1995 16

Lewis v. BT Investment Managers, 447 U.S. 27 (1980) 22

Louisiana Public Service Commission v. FCC, 476 U.S. 355 (1986) 9, 10

Middle South Energy, Inc. v. Arkansas Public Service Comm'n, 772 F.2d 404 (8th Cir. 1985), *cert. denied*, 474 U.S. 1102 (1986) 22, 23

Mississippi Power & Light Co. v. Mississippi, 487 U.S. 354 (1988) 16, 17

Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986) 16, 17

Northwest Cent. Pipeline v. State Corp. Comm'n of Kansas, 489 U.S. 493 (1989) 10, 24

Smith Cogeneration Management, Inc. v. Oklahoma Corp. Comm'n, 863 P.2d 1227 (Okla. 1993) 16

Southern Pacific Co. v. Arizona, 325 U.S. 761 (1945) 22

Wilson v. Harlow, 860 P.2d 293 (Okla. 1993), *cert. denied*, ___ U.S. ___, 114 S. Ct. 1067 (1994) 16

ADMINISTRATIVE DECISIONS

Cogeneration Coalition of America, Inc., 61 F.E.R.C. para. 61,252 (1992) 13

Connecticut Light & Power, 70 F.E.R.C. para. 61,027 (1995) 16

Connecticut Light & Power Company, 70 F.E.R.C. para. 61,012 *reconsideration denied*, 71 F.E.R.C. para. 61,035 (1995) 7

Doswell Limited Partnership, 50 F.E.R.C. para. 61,251 (1990) 19

Middle South Services, Inc., 33 F.E.R.C. para. 61,408 (1985), *reheard and clarified on other grounds*, 34 F.E.R.C. para. 61,342 (1986) 13, 18, 26

New York State Electric & Gas Co., 71 F.E.R.C. para. 61,017 (1995) 16

Orange and Rockland Utilities, Inc., 43 F.E.R.C. para. 61,067 (1988) 6, 26

Orange and Rockland Utilities, Inc., 43 F.E.R.C. para. 61,547 (1988) 6, 7

Orange and Rockland Utilities, Inc., 70 F.E.R.C. para. 61,014 (1995) 7, 26

Southern California Edison Co., 70 F.E.R.C. para. 61,215 (1995), *reconsidered on other grounds*, 71 F.E.R.C. para. 61,269 (1995) 11, 13, 19

West Penn Power Company, 71 F.E.R.C. para. 61,153, 1995 WL 265343 (F.E.R.C.) 13

UNITED STATES CONSTITUTION

U.S. Const. Art. I, § 8[3] 22

U.S. Const. Art. VI, cl. 2 9

STATUTES

16 U.S.C. § 796(18)(A)(1988) 2

16 U.S.C. § 824(b)(1988) 17

16 U.S.C. § 824(d)(1988) 17

16 U.S.C. § 824a-3(a)(1988) 2, 10, 11, 23

16 U.S.C. § 824a-3(b)(1988) 12, 21, 24

16 U.S.C. § 824a-3(d)(1988) 5, 12

16 U.S.C. § 824a-3(e)(1988) 18

16 U.S.C. § 824a-3(f)(1988) 2, 10, 23

16 U.S.C. § 824a-3(g)(1988) 25

16 U.S.C. § 824a-3(h)(1988) 25

REGULATIONS

18 C.F.R. § 292.101(b)(6)(1994) 3, 5

18 C.F.R. § 292.101(b)(7)(1994) 12

18 C.F.R. § 292.301(b)(1994) 3, 12

18 C.F.R. § 292.304(b)(2)(1994) 3, 12

18 C.F.R. § 292.304(1987) 18

18 C.F.R. § 292.401(a)(1987) 2, 11, 18, 23

18 C.F.R. § 292.401(1994) 11

18 C.F.R. § 292.601(c)(1994) 18

Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("Preamble"), 45 Fed. Reg. 12214 (1980) 6, 11, 12, 13, 25

MISCELLANEOUS

Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Proposed Regulations, 53 Fed. Reg. 9331 (1988) 7, 13

This page intentionally left blank.

No. 94-1868

In the
Supreme Court of the United States
October Term, 1994

North Carolina Power,
Petitioner,

v.

State of North Carolina ex rel. Utilities Commission,
Respondent.

Petition for a Writ of Certiorari to the
Supreme Court of North Carolina

ATTORNEY GENERAL'S BRIEF IN OPPOSITION

Respondent Michael F. Easley, North Carolina Attorney General, respectfully requests that this Court deny the petition for writ of certiorari seeking review of the opinion of the Supreme Court of North Carolina reported at 338 N.C. 412, 450 S.E.2d 896 (1994).

STATEMENT OF THE CASE

INTRODUCTION

Virginia Electric and Power Company, (Virginia Power)[1] contends this case raises a substantial federal question about the manner in which states address section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA § 210) and federal rules thereunder, and asserts that the challenged North Carolina decision conflicts with PURPA, federal rules, and federal and state decisions.[2] Virginia Power bases its position on an argument that PURPA and the federal rules require one state's regulatory authority to adopt a rate determined by a regulatory authority of another state for purchases by an electric utility from cogeneration facilities. A review of PURPA and federal rules thereunder shows that such uniformity among states is neither required nor intended. PURPA and Federal Energy Regulatory Commission (FERC) rules explicitly authorize "each" state to examine and determine rates under the federal framework for purchases by electric utilities from cogeneration facilities. 16 U.S.C. § 824a-3(f)(1988), 18 C.F.R. § 292.401(a)(1987). Nothing in the statute or federal rules obligates one state to accept a rate set by another state. Rather, the federal intent is that states should be afforded flexibility in the determina-

---

[1] Virginia Power operates in North Carolina under the name North Carolina Power and serves retail customers in North Carolina as well as Virginia.

[2] PURPA § 210 requires electric utilities to purchase electric power from cogeneration and small power production facilities. 16 U.S.C. § 824a-3(a)(1988). Only cogeneration facilities are involved in this case, and no further reference will be made to small power production facilities although most provisions apply the same for both. A cogeneration facility produces electric energy and steam or some other form of useful energy, such as heat. 16 U.S.C. § 796(18)(A)(1988).

tion of purchase rates. Thus, this case follows federal requirements and does not raise a substantial federal question.

Moreover, this case is affected by particular circumstances not likely to be of general interest and is therefore not appropriate for consideration by this Court. The North Carolina decision which Virginia Power challenges was influenced by the fact that a Virginia arbitrator departed from certain requirements of the federal rules in setting the purchase rate for Virginia, resulting in a purchase rate in excess of the "avoided cost" rate[3] authorized under federal law and rules. The Virginia arbitrator's determination was based "on the unique circumstances of the proceedings" (Pet. App. 189a), circumstances which are unlikely to be duplicated in Virginia or elsewhere.

BACKGROUND

This case arises from a retail rate case before the North Carolina Utilities Commission (the North Carolina Commission). In the course of that rate case, the North Carolina Commission examined for the first time the appropriateness of the purchase rate for capacity payments made by Virginia Power to Ultra Cogen Systems (Ultra Cogen) for cogeneration facilities known as Hadson Power 11-Southampton, Hadson Power 12-Altavista, and Hadson

---

[3] "Avoided cost" means the incremental costs to an electric utility which it would incur to generate power itself or purchase power from another source, but for the purchase from the cogeneration facility. *See* 18 C.F.R. § 292.101(b)(6)(1994). Rates for purchases from cogeneration facilities are set at full avoided cost, pursuant to FERC rules, unless the rates are negotiated among the parties. 18 C.F.R. §§ 292.301(b), 292.304(b)(2)(1994). When the Virginia arbitrator determined the Virginia purchase rate, he departed from the federal rules by relying only on the avoided cost of power otherwise generated by Virginia Power, and failing to consider the avoided cost of power available for purchase from other sources.

Power 13-Hopewell (the Hadson projects). (Pet. App. 35a)[4] At the time the rate case was heard, Virginia Power had not informed the North Carolina Commission about the Hadson projects or contracts for purchases from those projects, nor had it filed the contracts in North Carolina or otherwise sought approval by the North Carolina Commission of the capacity or energy costs of the projects, except in its application to include the costs in its North Carolina retail rates. (Pet. App. 35a) The rates Virginia Power paid for power from the Ultra Cogen projects had been set by arbitration over Virginia Power's objection in a proceeding before an arbitrator appointed by the Virginia State Corporation Commission (the Virginia Commission). (Pet. App. 187a-188a)

During the rate case in North Carolina, evidence was presented challenging the appropriateness of the rate Virginia Power paid Ultra Cogen for capacity. (Pet. App. 61a-76a) The North Carolina Commission considered the evidence and found that the rate determined by the Virginia arbitrator was well over twice as much as contemporaneous measures of avoided cost and was directly related to benefits expected for Virginia's economy from the cogeneration projects. (Pet. App. 74a-75a) It found that the Virginia arbitrator determined avoided cost of capacity based on an estimate of the cost of a power plant built by Virginia Power, but did not take into account other sources of purchased power.

The failure of the Virginia arbitrator to consider alternative sources of purchased power was significant. This truncated consideration was a departure from the provisions in PURPA §

---

[4] Ultra Cogen has been succeeded in interest by Hadson Power and later by LG&E Development, but is referred to in the North Carolina decisions and here as Ultra Cogen.

210 and federal rules which define avoided cost by reference to other sources of purchased power as well as the cost of power generated by the utility itself. 16 U.S.C. § 824a-3(d)(1988); 18 C.F.R. § 292.101(b)(6)(1994).

The failure to consider other power sources was especially problematic because Virginia Power was then supplying most or all of its new capacity requirements by purchased power. Prior to the time the arbitration proceedings were initiated by Ultra Cogen in early November 1987, Virginia Power had received many inquiries from cogenerators and other non utility generators interested in selling power. In fact, Virginia Power received so many offers in the spring and summer of 1986, that it had instituted a solicitation process and sent letters to potential sellers in December 1986 seeking 700 megawatts of capacity. (Pet. App. 31a) From a pool of offers totalling 5,083 megawatts, several projects were selected, six of which became operational producing capacity of about 1,400 megawatts. (Pet. App. 59a) Ultra Cogen participated in the 1986 solicitation but its proposals were rejected because its proposed price was excessive and Ultra Cogen was unwilling to accept certain terms and conditions. (Pet. App. 62a) Just fifteen months later (close to the time the arbitration proceedings were filed by Ultra Cogen), another bid solicitation was initiated by Virginia Power in March 1988 in which 1,750 megawatts of capacity were sought. From a pool of offers totalling 14,653 megawatts, Virginia Power selected several projects, seven of which became operational by the time of the rate case in North Carolina, producing about 1,000 megawatts of capacity. (Pet. App. 59a) Although the 1988 solicitation was underway when the arbitrator considered the avoided cost for the Ultra Cogen facilities, he did not require Ultra Cogen to participate in the bid solicitation, nor did he consider an estimate of what other sources of purchased power might have cost. (Pet. App.

172a) Virginia Power objected, arguing other sources of purchased power in the pending 1988 bid solicitation should be considered. The Virginia Commission ratified the arbitrator's decision, though, and Virginia Power did not appeal. (Pet. App. 66a)

Virginia Power did not bring its concerns about the purchase rate to the attention of the North Carolina Commission, and when the issue arose in a rate case filed in 1992, Virginia Power argued North Carolina was preempted under PURPA from examining the appropriateness of the purchase rate set by the Virginia arbitrator. In response, the North Carolina Commission found that it was not preempted by PURPA and FERC regulations from examining the purchase rate or contracts between Virginia Power and Ultra Cogen, and found the "avoided cost" could be determined differently in North Carolina than in Virginia. It pointed out that PURPA mandates action by each state (Pet. App. 67a), and FERC regulations both afford latitude in implementation and allow state regulatory agencies to review contracts for purchases as part of their regulation of electric utilities under state law. (Pet. App. 68a, citing Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 ("Preamble"), 45 Fed. Reg. 12214 at pp. 12230-3 (1980) (Appended to this Brief at App. 8a-10a, 19a).) Further, it noted that although PURPA and FERC regulations do not allow rates greater than avoided costs, Virginia might base higher rates on state law or policy.[5]

---

[5] FERC has waffled on the issue whether states may set rates in excess of avoided cost. In the preamble to its rules issued in 1980, FERC recognized the authority of states to set higher rates on the basis of state law, but said such rates were not based on PURPA. Since then, in a declaratory order issued April 14, 1988, FERC reversed its original position and declared that, prospectively, states could not impose purchase rates in excess of avoided cost. *Orange and*

(continued...)

The North Carolina Commission compared the purchase price for Ultra Cogen capacity with other contemporaneous measures of avoided costs for Virginia Power, and found the Ultra Cogen price out of line. The price difference was substantial. The annual capacity payments to Ultra Cogen average $341/kilowatt for the first fifteen years of operation, whereas the annual capacity payments average $141/kilowatt for projects which came from the 1986 solicitation, and $171/kilowatt for projects from the 1988 solicitation. The avoided costs set by the North Carolina Commission for small projects approved at the time the Hadson contracts were executed (which provide a cap on negotiated rates), would have resulted in significantly lower purchase rates for capacity. (Pet. App. 72a-73a) Moreover, the evidence showed the estimated cost for Virginia Power to build a plant and generate the power itself, on which the Ultra Cogen avoided cost was based, was a high estimate. (Pet. App. 73a)

The North Carolina Commission further found that the Virginia arbitrator's treatment of the Hadson projects was directly influenced by expected benefits from the projects unique to Virginia. It quoted the Virginia arbitrator's decision, which

---

[5](...continued)
Rockland Utilities, Inc., 43 F.E.R.C. para. 61,067 (1988)(*Orange and Rockland*). The effect of that order was stayed June 16, 1988 pending completion of judicial review and issuance of a final rule in a generic rulemaking, *Orange and Rockland Utilities, Inc.*, 43 F.E.R.C. para. 61,547 (1988), *citing Administrative Determination of Full Avoided Cost under PURPA* in Docket No. RM88-6-000 (ADFAC NOPR), leaving the issue open until this year, when FERC concluded in another case that states may not impose rates exceeding avoided cost for cogeneration sales at wholesale. *Connecticut Light & Power Company*, 70 F.E.R.C. para. 61,012, *reconsideration denied*, 71 F.E.R.C. para. 61,035 (1995). The same day it issued *Connecticut Light & Power*, FERC dismissed and vacated *Orange and Rockland*, finding that circumstances had changed in New York since that decision was first issued. *Orange and Rockland Utilities, Inc.*, 70 F.E.R.C. para. 61,014(1995).

"specifically recognizes that the Hadson contracts 'reflect negotiations and rulings based on the unique circumstances of these proceedings (including that [the projects] are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth).'" (Pet. App. 73a-74a) It noted that the arbitration petition filed by Ultra Cogen for one of the projects at The Lane Company indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista, Virginia, area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth of Virginia would result. The North Carolina Commission found Virginia consumers might reasonably be asked to pay the extra costs associated with economic development benefits of the Ultra Cogen projects, but found it unreasonable for North Carolina customers to pay such extra costs. (Pet. App. 74a)

The decision of the North Carolina Commission examined Virginia Power's avoided cost using contemporaneous measures (measures reflecting avoided cost at about the time the Virginia arbitration was initiated) and found the most appropriate measure was the average cost of capacity from the 1988 solicitation. (Pet. App. 76a) Virginia Power was allowed to recover capacity payments in retail rates based on that amount.

The North Carolina Supreme Court affirmed the decision of the Commission.

REASONS WHY THE WRIT SHOULD NOT BE GRANTED

I. THERE IS NOT A FEDERAL QUESTION OR CONFLICT AT ISSUE HERE: THE NORTH CAROLINA DECISION DOES NOT VIOLATE THE SUPREMACY CLAUSE.

A. NORTH CAROLINA ACTED UNDER PROPER AUTHORITY GRANTED IN PURPA AND FERC REGULATIONS AND ITS DECISION WAS NOT PREEMPTED BY A VIRGINIA CORPORATION COMMISSION DETERMINATION.

Virginia Power contends the decision of the North Carolina Commission, affirmed by the North Carolina Supreme Court, raises important federal issues concerning the manner in which PURPA should be implemented by state regulators, and conflicts with decisions of other state and federal courts as well as the decisions of this Court. In support of these contentions, it says PURPA and FERC rules should be read to give preemptive effect to a decision of one state setting rates for purchases from cogeneration facilities, so that a second state regulatory agency is required to adopt rates set by the first without opportunity for examination or consideration of the appropriate rate by the second state. This position ignores the intent of PURPA and FERC rules prescribed thereunder.

The Supremacy Clause of the U.S. Constitution says the laws of the United States made pursuant to the constitution shall be the supreme Law of the Land. U.S. Const. Art. VI, cl. 2. Under this clause, Congress has the power to preempt state law. *Louisiana Public Service Commission v. FCC*, 476 U.S. 355 (1986). In any preemption analysis, the critical issue is the

determination of Congressional intent. *Id.*; *Northwest Cent. Pipeline v. State Corp. Comm'n of Kansas*, 489 U.S. 493, 509 (1989). *Louisiana* lists the following bases for preemption: 1) when Congress, in enacting a federal statute, expresses a clear intent to preempt state law; 2) when there is outright or actual conflict between federal and state law; 3) where compliance with both federal and state law is in effect physically impossible; 4) where there is implicit in federal law a barrier to state regulation; 5) where Congress has legislated comprehensively, thus occupying an entire field of regulation and leaving no room for the states to supplement federal law; or 6) where the state law stands as an obstacle to the accomplishment and execution of the full objectives of Congress. *Id.* (citations omitted) When a federal agency acts within the scope of its congressionally delegated authority, it may preempt state regulation. 476 U.S. at 368-369.

Congress' intent concerning the authority granted to federal and state agencies under PURPA § 210 is clear: FERC is required to prescribe rules governing arrangements between electric utilities and cogeneration facilities, after consultation with state regulators and others, 16 U.S.C. § 824a-3(a), and "*each* State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for *each* electric utility for which it has ratemaking authority." 16 U.S.C. § 824a-3(f)(1988) (Emphasis supplied.) Thus, under the plain language of PURPA, Congress expressly required "each" state to address arrangements between cogeneration facilities and electric utilities, by implementation of federal rules, and actions by state agencies taken in compliance with the federal rules are not preempted. Congress has not limited state implementation authority to facilities located within the state, nor has it limited the authority to one of two or more states which has ratemaking authority over a particular utility. Certainly, Congress is aware that an electric utility may be

subject to the ratemaking authority of more than one state. Thus, if uniformity were considered imperative by Congress, it would not have called for implementation of the arrangements by "each" state authority for "each" utility.[6]

FERC rules promulgated under PURPA § 210 clearly intend to grant states great latitude in the methods they use for implementation. FERC explicitly said so in the Preamble to the rules. *Preamble*, 45 Fed. Reg. at 12230 (App. 8a-9a); *also see Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 742 (1982) (*Mississippi*). The rules themselves say that states may comply with the statutory requirements of PURPA § 210 by issuing regulations, by resolving disputes on a case-by-case basis, or by taking any other action reasonably designed to implement the rules. *Id.*, 18 C.F.R. § 292.401(a)(1987).[7] FERC extended the states this latitude "partly in recognition of the important role which Congress intended to give the states under PURPA." *Southern California Edison Co.*, 70 F.E.R.C. para. 61,215 at p. 61,675 (1995) (citations omitted), *reconsidered on other grounds*, 71 F.E.R.C. para. 61,269 (1995).

FERC is charged under PURPA with prescribing such rules as it determines are necessary to encourage cogeneration. Those rules must require electric utilities to offer to sell electricity to and purchase electricity from cogeneration facilities. 16 U.S.C.

---

[6] The North Carolina Commission noted in this case that a lack of uniform rate treatment is not unique to PURPA. Virginia and North Carolina may apply different methodologies for allocating costs among the states in retail rate cases with the result that Virginia Power may recover more or less than its total costs. (Pet. App. 75a)

[7] In 1992, FERC revised its rules concerning implementation to remove obsolete language. 18 C.F.R. § 292.401 (1994), 57 Fed. Reg. 21734.

§ 824a-3(a). The rules must also ensure that the rates for required purchases are just and reasonable to the electric utility's consumers and in the public interest, and are not discriminatory against cogenerators. 16 U.S.C. § 824a-3(b)(1988). The rules must not provide for a rate which exceeds the utility's "incremental cost to the electric utility of alternative electric energy," 16 U.S.C. § 824a-3(b)(1988), the equivalent of the term "avoided cost" used in FERC regulations. *American Paper Inst. v. American Elec. Power Serv. Corp.*, 461 U.S. 402 (1983)(*American Paper*); 16 U.S.C. § 824a-3(d)(1988); 18 C.F.R. § 292.101(b)(7)(1994).

The FERC rules mirror these statutory requirements. They require utilities to offer to pay purchase rates based on full avoided cost unless the rates are negotiated among the parties. *See American Paper*, 461 U.S. 402; 18 C.F.R. § 292.304(b)(2)(1994), 18 C.F.R. § 292.301(b)(1994). The determination of what those avoided cost rates should be is left to the state authorities.

The rules clearly intend to grant state regulators broad discretion in the determination of utilities' avoided costs. When promulgating its rules, FERC considered whether it should issue specific rules which state regulators would adopt without change, and rejected that approach, saying, "The Commission does not find this proposal to be appropriate at this time, and believes that providing an opportunity for experimentation by the states is more conducive to development of these difficult rate principles." 45 Fed. Reg. at 12231 (App. 9a) FERC recognized that "economic and regulatory circumstances vary from State to State and utility to utility." *Id.* at 12231 (App. 9a)

Since the federal rules were promulgated, FERC has expressly recognized in the course of several proceedings that states may use different methodologies for determining avoided

cost. *Southern California Edison Company*, 70 F.E.R.C. para. 61,215 (1995), *reconsidered on other grounds*, 71 F.E.R.C. para. 61,269 (1995); *Cogeneration Coalition of America, Inc.*, 61 F.E.R.C. para. 61,252 (1992); *Middle South Services, Inc.*, 33 F.E.R.C. para. 61,408 at p. 61,789 (1985), *reheard and clarified on other grounds*, 34 F.E.R.C. para. 61,342 (1986); *Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Proposed Regulations*, 53 Fed. Reg. 9331 (1988), FERC Statutes and Regulations para. 32,457 (1988)(ADFAC NOPR); *cf. West Penn Power Company*, 71 F.E.R.C. para. 61,153, 1995 WL 265343, at *13 (F.E.R.C.)(1995). As a result, FERC has acknowledged the avoided costs for the same project may differ in one state from another. 33 F.E.R.C. at p. 61,789; 53 Fed. Reg. 9331. Recently, while reaffirming the key role of states in setting avoided costs, FERC has expressed the need to ensure that states use procedures which ensure that purchase rates do not exceed avoided cost in light of the facts that the cogeneration industry is now developed and electric utilities are facing increasing competition. 70 F.E.R.C. at p. 61,675.

Further, FERC has expressly authorized state review of contracts between cogenerators and utilities in utility rate cases. As FERC stated in the Preamble to the Rules, "These rules, and the exemptions being provided by these rules, are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities. Such authority may continue to be exercised if consistent with the terms, policies and practices under sections 210 and 201 of PURPA and this Commission's implementing regulations." 45 Fed. Reg. at 12233 (App. 19a).

In short, there is not any basis in PURPA § 210 or federal rules for the proposition that Congress or FERC intended that one state's avoided cost determination should preempt another state from conducting its own examination of the appropriate avoided cost in determining whether a purchase rate is reasonable.

Here, Virginia Power presented the North Carolina Commission with information about the Ultra Cogen facilities for the first time in the context of a retail rate case. The North Carolina Commission acted within its authority under the Federal Power Act to set retail rates, and under its authority in PURPA and FERC rules to examine the appropriate rate for purchases from cogeneration facilities. It concluded from the evidence that the Virginia arbitrator's decision did not consider other sources of purchased power available to the Company even though avoided cost is defined under PURPA § 210 and FERC with reference to the incremental costs of both purchased power and power generated by the Company itself. The North Carolina Commission concluded that the purchase rate set by the Virginia arbitrator was more than twice the rate which would result if other contemporaneous measures of avoided cost were used. Further, the North Carolina Commission concluded that the Virginia arbitrator was directly influenced in his decision by factors of peculiar benefit to Virginia. Therefore, the North Carolina Commission made its own determination of a reasonable rate using contemporaneous measures, and allowed that avoided cost amount in Virginia Power's retail rates. The determination, affirmed by the North Carolina Supreme Court, properly applies the federal statute and rules, and does not raise a substantial federal issue.

B. VIRGINIA HAS NOT RAISED A SUBSTANTIAL FEDERAL QUESTION AND THE NORTH CAROLINA DECISION DOES NOT CONFLICT WITH DECISIONS OF OTHER COURTS.

In support of its Petition, Virginia Power asserts a number of reasons why this Court should hear this case.

1. CONFLICT WITH VIRGINIA.

Virginia Power argues the North Carolina decision in this case puts North Carolina in conflict with Virginia. However, as shown earlier, PURPA § 210 and FERC rules do not require uniformity among states in the manner in which each implements the rules or the method by which each determines avoided costs. Moreover, the Virginia arbitrator's decision was ratified by the Virginia Commission, but was not appealed to Virginia appellate courts. (Pet. App. 11a, 192a) Hence there is not a conflict between the States of North Carolina and Virginia, as Virginia Power suggests.[8]

2. CONFLICTS WITH DECISIONS OF OTHER COURTS AND FERC.

Virginia Power further contends that the North Carolina decision "is squarely in conflict" with decisions by the Third Circuit of the Court of Appeals, FERC, and the Oklahoma

---

[8] Presumably, the Virginia Commission would not support an interpretation of PURPA § 210 and FERC Rules which would give preemptive effect to a North Carolina Commission determination of avoided cost, particularly if it found the decision had failed to follow the federal rule and had taken into account economic development benefits peculiar to North Carolina.

Supreme Court.[9] Not one of the cases addresses the issue Virginia Power raises in this case, however. While the cases may support the proposition that a state should not reconsider an avoided cost rate once it has approved the rate and a binding contract has been formed, they do not presume to restrict a state from examining rates where, as here, it has not previously considered or approved the rate or contracts.

3. CONFLICTS WITH DECISIONS OF THIS COURT.

Virginia Power cites this Court's decisions in *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986) (*Nantahala*), *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354 (1988)(*MP&L*), and *Federal Energy Regulatory Comm'n v. Mississippi*, 456 U.S. 742 (1982)(*Mississippi*) in support of its arguments that North Carolina is preempted by the Virginia arbitrator's decision. This reliance is ill-founded. In *Mississippi*, the Court found that Congress acted within its powers under the Commerce Clause when it required electric utilities to purchase power from cogenerators, and found provisions requiring states to implement mandatory FERC guidelines were not unconstitutional under principles of state sovereignty contained in the Tenth Amendment. 487 U.S. 354. While the case may be cited for the proposition that states must follow the federal statute and mandato-

---

[9] *See* Petition pp. 17-18, citing *Freehold Cogeneration Associates, L.P. v. Bd. of Regulatory Comm'rs of New Jersey*, 44 F.3d 1178 (3rd Cir. 1995), *cert. pet. pending*, *New Jersey Division of Ratepayer Advocate v. Freehold Cogeneration Associates, L.P.*, Docket No. 94-1995; *Connecticut Light & Power*, 70 F.E.R.C. para. 61,027 at pp. 61,029-30 (1995); *New York State Electric & Gas Co.*, 71 F.E.R.C. para. 61,017 (1995); *Wilson v. Harlow*, 860 P.2d 293 (Okla. 1993), *cert. denied*, ___ U.S. ___, 114 S. Ct. 1067 (1994); *Smith Cogeneration Management, Inc. v. Oklahoma Corp. Comm'n*, 863 P.2d 1227 (Okla. 1993).

ry federal rules, there is nothing in the case to suggest that one state's authority to act under the rules is preempted by actions of another state authority. On the contrary, the case recognizes that state regulatory authorities are charged under the federal statute and rules with implementation of the rules. 456 U.S. at 759. Further, as this Court stated in *Mississippi*, the states are afforded latitude in the methods they may use to implement the federal rules. 456 U.S. at 751. Although this Court discussed one method -- dispute resolution on a case-by-case basis -- as a mechanism by which a state might implement the FERC rules, it also noted that the FERC rules allow states to issue regulations or take any other action reasonably designed to implement the rules. *Id.* at 751, 760. Thus, Virginia Power mischaracterizes *Mississippi* when it suggests that *Mississippi* stands for the notion that a state's duty to implement federal rules under PURPA § 210 requires implementation only by means of case-by-case dispute resolution.

The *Nantahala* and *MP&L* cases are not good support for Virginia Power's position in this Petition either. Those cases address the preemptive effect of a rate or apportionment set by FERC for a wholesale transaction subject to regulation under the Federal Power Act. 476 U.S. 953; 487 U.S. 354; 16 U.S.C. §824(b) and §824(d)(1988). That is not the case here; the Virginia arbitrator's decision was not a rate set by FERC. Virginia Power reaches beyond the intent of Congress when it suggests that a Virginia arbitrator's determination is "equivalent" to the preemptive effect of FERC orders establishing wholesale rates under the Federal Power Act.[10] As Virginia Power acknowledges elsewhere in its Petition, Congress carved out an exception to FERC's

---

[10] Virginia determines rates, taking into account their impact on Virginia customers, whereas FERC is required to take into account the impact of rates on all customers.

exclusive jurisdiction over wholesale sales in interstate commerce upon the passage of PURPA. (*See* Petition at p. 6.) Under FERC regulations authorized by PURPA, the purchase price for power sold by a cogeneration facility is exempt from regulation by FERC under the relevant provisions of the Federal Power Act, 16 U.S.C. § 824a-3(e)(1988), 18 C.F.R. § 292.601(c)(1994), and the rate is determined under federal rules implemented by *each* state for utilities subject to their ratemaking authority. 18 C.F.R. §§ 292.304, 292.401(a)(1987).

Moreover, in *Middle South Services, Inc.*, 33 F.E.R.C. para. 61,408 (1985), *reheard and clarified on other grounds*, 34 F.E.R.C. para. 61,342 (1986), FERC specifically recognized that different states may use different methodologies when setting avoided cost rates for the utilities they regulate. *Middle South* raised the concern that there may be a lack of consistency in avoided cost pricing methodologies among the states, because each state commission is "charged primarily with the responsibility of protecting the economic interests of separate constituents." 33 F.E.R.C. at 61,789, *citing* Middle South initial brief (Phase II), pp. 27-28. FERC responded to this concern:

> While there clearly is potential for diverse approaches in State implementation, diversity is inherent in the latitude our rules give to States in implementing section 210. 33 FERC at 61,789.

4. DICTA IN DOSWELL.

In support of its Petition, Virginia Power also cites a FERC order addressing rates for Doswell Limited Partnership, an

independent power producer[11] which had entered agreements to sell electricity to Virginia Power. *Doswell Limited Partnership*, 50 F.E.R.C. para. 61,251 (1990) (Pet. App. 140a). Virginia Power contends that FERC "impliedly affirmed" the Virginia arbitrator's decision concerning the Ultra Cogen facilities in the *Doswell* order when it referenced the Virginia Commission decision ratifying the arbitrator's decision. It is clear, though, that the appropriateness of the purchase rate set for the Ultra Cogen facilities was not an issue raised before FERC in the Doswell case. Moreover, the purchase rate for Doswell was $146/kilowatt, while the rates for Ultra Cogen were $341/kilowatt, although both were purportedly based on estimates of the cost of constructing the same plant and Doswell has a higher capacity rating, indicating it has more attractive operating costs than the Ultra Cogen facilities. (Pet. App. 730) The difference between Doswell's purchase rate and Ultra Cogen's was that Doswell's was determined during the 1986 solicitation, whereas the purchase rates for Ultra Cogen were set without consideration of the cost of alternative sources of purchased power. In *Southern California Edison Company*, 70 F.E.R.C. para. 61,215 (1995), *aff'd in relevant part on reconsideration*, 71 F.E.R.C. para. 61,269, the FERC held that a determination of "avoided cost" does not reflect avoided cost as defined by PURPA where it uses a benchmark based only on the purchasing utility's cost of generating energy and fails to take into account what it would cost to purchase such energy from another source.

5. Use of Appropriate Date.

Virginia Power also suggests that North Carolina failed to use the right date to measure avoided cost in this case. This

---

[11] Doswell is an independent generator which does not qualify as a cogeneration facility.

suggestion is not supported by the facts. The North Carolina Commission considered measures of avoided cost contemporaneous to the time the arbitration petitions were filed in November 1987. It considered the average purchase rate for capacity from contracts entered as a result of competitive bids initiated less than a year earlier in December 1986, and just a few months later in March 1988, as well as rates set by the North Carolina Commission for small projects at the time the Ultra Cogen petitions were filed. (Pet. App. 72a-73a) The bid solicitations addressed many offers Virginia Power had received for capacity throughout the period. Virginia Power implies that the difference between the rate of $341/kilowatt set for Ultra Cogen and the average rate of $171/kilowatt which came from the 1988 solicitation is due to a drop in avoided costs after the time the arbitration petitions were filed. This ignores the fact that the purchase rates produced by the 1986 solicitation averaged $141/kilowatt, even lower than those produced in the 1988 solicitation. The North Carolina Commission (and the North Carolina Supreme Court) clearly attributed the difference in rates to the facts that the Virginia arbitrator failed to consider the avoided cost of other sources of purchased power, and that he took into account economic development benefits to Virginia.

6. THE DUTIES TO ENCOURAGE COGENERATION AND PROTECT CONSUMERS.

Virginia Power suggests that North Carolina failed to consider the Virginia arbitrator's decision when it examined the purchase rate for the Ultra Cogen facilities, ignoring its obligation to encourage development of cogeneration facilities. In fact, the North Carolina Commission examined the Virginia proceedings carefully and thoroughly, and used avoided cost methodology in its analysis. While North Carolina might have deferred to the

Virginia arbitrator's determination if the propriety of the avoided cost rate had not been raised, North Carolina was faced with considerable evidence that the Virginia arbitrator's rate substantially exceeded Virginia Power's avoided cost as that cost is determined under PURPA and FERC rules. North Carolina recognized its responsibility under PURPA to limit the purchase rate to avoided cost, to ensure that the rate is just and reasonable to Virginia Power's consumers. *See* 16 U.S.C. § 824a-3(b)(1988). Accordingly, it was proper for North Carolina to examine the issue and reach a determination.

Finally, Virginia Power says that the North Carolina decision "deals a serious blow to PURPA" and PURPA will not work if the North Carolina decision is allowed to stand. By this argument, Virginia Power suggests that state determinations of avoided cost must be uniform to work. FERC decided otherwise when it refused to set a uniform federal rule in 1980. Since then, it has acknowledged repeatedly the authority of states to determine avoided cost rates. Certainly, this has not chilled the development of cogeneration facilities, an industry which has flourished in the intervening years. If lack of uniformity among state authorities becomes problematic, that is a matter to be presented to Congress or FERC for reexamination of the statute and rules.

Virginia Power's objections about North Carolina's decisions do not accurately represent an intention of Congress or FERC that one state's determination of avoided cost has preemptive effect over another state with respect to the resulting purchase rate. There is not a conflict with federal statutes, rules, or decisions; North Carolina decided properly. Certiorari is not appropriate in this case.

II. NORTH CAROLINA'S DECISION DOES NOT VIOLATE INTERSTATE COMMERCE.

Virginia Power also seeks review of this case based on an argument that the North Carolina decision violates the Commerce Clause of the United States Constitution and conflicts with federal Commerce Clause decisions. This argument lacks merit. Specific federal statutory and regulatory provisions authorize and require North Carolina to address arrangements between Virginia Power and cogenerators, and the North Carolina decision examined the arrangements in a manner consistent with the intent of those federal provisions. There is not a commerce clause violation in this case, and there is not a conflict with federal decisions.

Under Article I, § 8 [3] of the U.S. Constitution, Congress shall have the power "To regulate commerce . . . among the several states . . .". U.S. Const. Art. I, § 8[3]. Congress may confer upon the states the ability that they would otherwise not enjoy to restrict the flow of interstate commerce. *Lewis v. BT Investment Managers*, 447 U.S. 27, 44 (1980); *Southern Pacific Co. v. Arizona*, 325 U.S. 761, 769 (1945); *Middle South Energy, Inc. v. Arkansas Public Service Comm'n*, 772 F.2d 404 at 414 (8th Cir. 1985), *cert. denied*, 474 U.S. 1102 (1986). Thus, in *Mississippi*, cited earlier, this Court recognized that federal law has expressly left regulation of intrastate and retail electric power transactions to the states, although Congress has the power to regulate in that area under the Commerce Clause. 456 U.S. 742. Similarly, this Court found Congress has the power under the Commerce Clause to regulate the relationships between cogenerators and electric utilities to protect interstate commerce, 456 U.S. at 758, and Congress has explicitly divided the responsibility for regulation of such relationships between federal and state agencies, conferring on each state the authority, indeed the requirement, to

implement federally prescribed rules for each utility subject to its ratemaking authority. 16 U.S.C. § 824a-3(a),(f)(1988). Hence, the North Carolina Commission is specifically authorized by Congress to act with respect to arrangements between cogenerators and Virginia Power, and Virginia Power's argument to the contrary is untenable.

Virginia Power portrays the North Carolina decision as one based on state retail ratemaking authority, and suggests that federal provisions concerning the relationship between Virginia Power and cogenerators were disregarded by the North Carolina Commission. But as has been discussed elsewhere, this is just not the case. The facts show that the purchase rate between Virginia Power and Ultra Cogen was reviewed in North Carolina consistently with the PURPA-FERC avoided cost framework. (Pet. App. 4a-9a, 66a-69a, 72a-76a) The North Carolina Commission order considered the purchase rate set by the Virginia arbitrator, and made its own examination of an appropriate rate by analyzing alternative measures of avoided cost. North Carolina's action was within the scope of review which *each* state is authorized to conduct by PURPA and FERC regulations. *See Mississippi* at 751; 16 U.S.C. § 824a-3(f); 18 C.F.R. § 292.401(a).

Virginia Power argues that the North Carolina decision conflicts with the decision of the Federal Eighth Circuit in *Middle South Energy v. Arkansas Public Service Comm'n*, 772 F.2d 404. In that case, FERC reallocated purchase obligations of Middle South's operating companies to purchase power from a nuclear plant over the objection of the Arkansas commission, and shortly thereafter, the Arkansas commission initiated its own inquiry into the burden of high cost power associated with the plant. The court found the Arkansas proceeding was motivated by economic protectionism and violated interstate commerce. This case does not

involve such a conflict with FERC, nor does it involve economic protectionism. Congress and FERC clearly envision and authorize a role for "each" state regulatory authority in determining purchase rates for cogenerated power and nothing in PURPA or FERC rules says that one state must adopt a determination made by another state. In granting state authorities the power to implement FERC rules, Congress must have contemplated some impact on interstate commerce. There would be little point to granting authority to "each" state, if a state's exercise of this authority were not constitutionally enforceable. *Cf.*, *Northwest Central Pipeline Corporation v. State Corporation Commission of Kansas*, 489 U.S. 493, 523-524 (1989).

North Carolina has a legitimate interest in addressing avoided cost rates, both under its federal charge to implement PURPA, and in the context of state regulation of retail rates to customers. PURPA specifically limits the federal role in encouraging cogeneration when it says no rule provided pursuant to PURPA shall require rates in excess of the avoided cost to electric utilities. 16 U.S.C. §824a-3(b)(1988). If North Carolina is required to adopt Virginia rates as the Petitioner suggests -- notwithstanding a determination that Virginia's rates exceed avoided cost and take into account economic development benefits peculiar to Virginia -- this undermines the clear federal framework. Federal interstate commerce purposes are not thereby advanced.

Contrary to Petitioner's assertion that the North Carolina decision was motivated by economic protectionism, there is nothing in the facts of this case to suggest that North Carolina looked at benefits to North Carolina at all when it reviewed the Ultra Cogen project purchase rates. The North Carolina Commission order does not call for more North Carolina-located facilities, or require use of North Carolina fuels, nor is there any evidence

of a disregard for Virginia facilities. The North Carolina Commission did what it is authorized to do under PURPA: it assessed what an appropriate purchase rate would be, using contemporaneous measures of avoided cost, and allowed recovery of a purchase rate on that basis. In doing so, the North Carolina Commission used a measure of avoided cost which resulted in the smallest reduction in rates of the several measures introduced into evidence. (Pet. App. 73a)

The North Carolina decision in this case is consistent with both state and national interests. FERC acknowledges its rules promulgated under PURPA may not produce uniform results, but recognizes the benefit of experimentation by the states, and the advantage that states may take into account varying economic and regulatory circumstances. *Preamble*, 45 Fed. Reg. at 12230-1 (App. 8a-9a) If the North Carolina decision affects interstate commerce in that it applies a different regulation than Virginia, the effect is only to nullify the effect of Virginia economic protectionism. It does not compromise national goals; rather it implements them.

Moreover, this case involves facts which are unlikely to repeat themselves in other cases. Virginia Power did not seek review of the purchase rate or contracts for the Ultra Cogen facilities in North Carolina until this rate case was heard, although it disagreed with the Virginia arbitrator's determination. Virginia Power could have avoided the result in this case if it had sought contemporaneous determinations of the rate in North Carolina and Virginia. Further, it could have appealed the Virginia arbitrator's decision to Virginia courts or taken the matter to FERC for enforcement of federal rules, on the ground that the Virginia arbitrator's decision exceeded PURPA. 16 U.S.C. § 824a-3(g),(h)(1988). Virginia Power may still take steps to address the

problematic effect of the Virginia arbitrator's decision by bringing the matter to the attention of the Virginia Commission and requesting an allocation of the Ultra Cogen contract prices to Virginia ratepayers, to the extent the prices exceed federal avoided cost.[12]

For these reasons, the North Carolina decision complies with Congress' express intent requiring state implementation of federal rules governing the arrangements between cogenerators and electric utilities. There is not a substantial federal issue, nor is there a conflict with federal cases.

---

[12] FERC suggested in *Middle South Services, Inc.*, 33 F.E.R.C. at pp. 61,789-790, that a multistate utility may localize the effect of an avoided cost determination by allocating the cost of purchases from qualifying facilities to the purchasing state. In another case, where one state set purchase rates in excess of avoided cost, FERC suggested localizing the effect by allocating the excessive cost to the state setting the rate above avoided cost. *Orange and Rockland*, 43 F.E.R.C. at p. 61,196. That case was stayed and later vacated on findings of changed circumstances. 43 F.E.R.C. para. 61,547; 70 F.E.R.C. para. 61,014.

CONCLUSION

In view of the foregoing, the Respondent Attorney General respectfully requests this Court deny the petition for writ of certiorari.

Respectfully submitted,

MICHAEL F. EASLEY
North Carolina Attorney General

Margaret A. Force
Assistant Attorney General

North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602-0629
(919) 733-7214

July 17, 1995

* Counsel of Record

This page intentionally left blank.

APPENDIX

PORTIONS OF THE PREAMBLE TO
18 CFR PART 292 . . . . . 1a

This page intentionally left blank.

PORTIONS OF THE PREAMBLE TO 18 CFR PART 292

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79-55, Order No. 69]

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities, and provide for the exemption of qualifying facilities from certain federal and State regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

Effective Date: March 20, 1980

* * *

SUPPLEMENTARY INFORMATION:
Issued February 19, 1980.

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires the Federal Energy Regulatory Commission (Commission) to prescribe rules as the Commission determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities. Additionally, section 210 of PURPA authorizes the Commission to exempt qualifying facilities from certain Federal and State law and regulation.

Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities, and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Thus, by using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities use biomass, waste, or renewable resources, including wind, solar and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally required to purchase the electric output, at an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulation as an electric utility.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act.

I. Procedural History

On June 26, 1979, in Docket No. RM79-54,[1] the Commission issued proposed rules to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 PURPA. Such qualifying facilities are entitled to avail themselves of the rate and exemption provisions under section 210 of PURPA; and qualifying cogeneration facilities are eligible for exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978.[2] The Commission will soon issue a final rule in Docket No. RM79-54.

As part of the rulemaking process in this docket, the Commission issued a Staff Discussion Paper[3] on June 27, 1979, addressing issues arising under section 210 of PURPA.

Public hearings on RM79-54 and the Staff Discussion Paper (RM79-55) were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking under Section 210 of PURPA in Docket No. RM79-55.[4] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the

---

[1] 44 FR 38873, July 3, 1979.

[2] 44 FR 65744, November 15, 1979.

[3] 44 FR 38863, July 3, 1979.

[4] 44 FR 61190, October 24, 1979.

proposed rules in Docket Nos. RM79-54 and RM79-55. In a Request for Further Comments,[5] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested parties, the Commission staff held public hearings in Seattle on November 19, 1979, in New York on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment.

After consideration of the comments, the Commission Staff made available a final draft rule on January 29, 1980. State public utility commissioners were invited to comment on the draft at a public meeting held on February 5, 1980. Representatives of electric utilities were invited to comment at a public meeting held on February 8, 1980. The Commission Staff also made itself available to any other interested parties who wished to comment. All of the comments were considered in the formulation of this final rule.

In the Staff Discussion Paper and the Request for Further Comments, it was stated that any environmental effects attributable to this program would result from the combined effect of these two rulemaking proceedings. As noted previously, the Commission intends to issue final rules in Docket No. RM79-54 in the near future. At that time, the Commission will also make available its final Environmental Assessment.

---

[5] 44 FR 61977, October 29, 1979.

II. Summary

These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilitics on a nondiscriminatory basis, and at a rate that is just and reasonable and in the public interest; and that they must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilities' own generation.

The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance

of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

III. Section-by-Section Analysis

* * *

Subpart C--Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

* * *

Relation to State Programs

The Commission has become aware that several States have enacted legislation requiring electric utilities in that State to purchase the electrical output of facilities which may be qualifying facilities under the Commission's rules at rates which may differ from the rates required under the Commission's rules implementing section 210 of PURPA.

This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.

If a State program were to provide that electric utilities must purchase power from certain types of facilities, among which are included "qualifying facilities," at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on the Commission's rules.

A facility which provides energy or capacity to a utility under State authority may nevertheless seek to obtain exemption from the Federal Power Act, the Public Utility Holding Company Act, and State regulation of electric utilities as available under section 210(e) of PURPA. The Commission notes that the States lack the authority to exempt a facility from the Federal Power Act or Public Utility Holding Company Act. The Commission finds no inconsistency in a facility's taking advantage of section 210 in order to obtain one of its benefits, while relying on other authority under which to buy from or sell to a utility.

* * *

Subpart D--Implementation

Summary of this Subpart

Rules in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying the nature of the obligation to implement the Commission's rules under section 210.

These rules afford the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the Commission's rules, provided that the manner chosen is reasonably designed to implement the

requirements of Subpart C. The Commission recognizes that many States and individual nonregulated electric utilities have ongoing programs to encourage small power production and cogeneration. The Commission also recognizes that economic and regulatory circumstances vary from State to State and utility to utility. It is within this context--in recognition of the work already begun and of the variety of local conditions--that the Commission promulgates its regulations requiring implementation of rules issued under section 210.

Because of the Commission's desire not to create unnecessary burdens at the State level, these rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply to the Commission for a waiver if it can demonstrate that compliance with certain requirements of Subpart C is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210.

Several commenters expressed their concern that State regulatory authorities would not be able adequately to implement the Commission's rules, and therefore, recommended that the Commission issue specific rules which the State regulatory authorities would adopt without change. The Commission does not find this proposal to be appropriate at this time, and believes that providing an opportunity for experimentation by the States is more conducive to development of these difficult rate principles.

Implementation

Section 210(f) of PURPA requires that within one year after the date that this Commission prescribes its rules under subsection (a), and within one year of the date any of these rules is revised, each State regulatory authority and each nonregulated

electric utility, after notice and opportunity for hearing, must implement the rules or revisions thereof, as the case may be.

The obligation to implement section 210 rules is a continuing obligation which begins within one year after promulgation of such rules. The requirement to implement may be fulfilled either (1) through the enactment of laws or regulations at the State level, (2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission, or (3) by any other action reasonably designed to implement the Commission's rules.

Review and Enforcement

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a state regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210. Under subsection (g), review may be obtained pursuant to procedures set forth in section 123 of PURPA. Section 123(c)(1) contains provisions concerning judicial review and enforcement of determinations made by State regulatory authorities and nonregulated utilities under subtitle A, B, or C of Title I in the appropriate state court. These provisions also apply to review of any action taken to implement the rules under section 210. This means that persons can bring an action in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations.

Section 123(c)(2) of PURPA provides that persons seeking review of any determination made by a Federal agency may bring an action in the appropriate Federal court. This distinction between Federal agencies and non-Federal agencies also applies to

review of enforcement of the implementation of the rules under section 210.

Finally, the Commission believes that review and enforcement of implementation under section 210 of PURPA can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly--namely, put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement of the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, or its regulations or of any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce the implementation of regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but also provided that the Commission may serve as a forum for review and enforcement of the implementation of this program.

§292.401 Implementation by state regulatory authorities and nonregulated electric utilities

Paragraph (a) of §292.401 sets forth the obligation of each State regulatory authority to commence implementation of Subpart C within one year of the date these rules take effect. In complying with this paragraph the State regulatory authorities are required to provide for notice of and opportunity for public hearing. As described in the summary of this subpart, such implementation

may consist of the adoption of the Commission's rules, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement Subpart C.

This section does not cover one provision of Subpart C which is not required to be implemented by the State regulatory authority or nonregulated electric utility. This provision is §292.302 (Availability of electric utility system cost data), the implementation of which is subject to §292.402, discussed below.

Subsection (b) sets forth the obligation of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart C. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart C through issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement that subpart.

Paragraph (c) sets forth a reporting requirement under which each State regulatory authority and nonregulated electric utility is to file with the Commission, not later than one year after these rules take effect, a report describing the manner in which it is proceeding to implement Subpart C.

Comments received regarding this section indicated a concern that the obligation of a State regulatory authority or nonregulated utility "to commence implementation * * * within one year * * *" did not provide any guidance as to when the process must be completed. The Commission notes that the intention of this section is that the State regulatory authorities and nonregulated utilities have one year in which to establish procedures and that at

the end of that year each State must be prepared to entertain applications. The phrase "commence implementation" is intended by the Commission to connote that implementation of these rules is a continuing process and that oversight will be ongoing.

§292.402 Implementation of reporting objectives.

The obligation to comply with §292.302 is imposed directly on electric utilities. This is different from the rest of Subpart C where the obligation to act is imposed on the State regulatory authority or the nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA and other laws within the Commission's authority to require this reporting.

Any electric utility which fails to comply with the requirements of §292.302(b) is subject to the same penalties as it might receive as a result of a failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA. As stated earlier in this preamble, the data required by §292.302 will form the basis from which the rates for purchases will be derived; §292.302 is thus a critical element in this program. The Commission believes that, with regard to utilities subject to section 133 of PURPA, the Commission may exercise its authority under section 133 to require the data required by §292.302(b) on the basis that the Commission finds such information necessary to allow determination of the costs associated with providing electric services. With regard to utilities not subject to section 133, if they fail to provide the data called for in §292.302(c), the Commission may compel its production under the Federal Power Act and other statutes which provide the Commission with authority to require reporting of such data.

§292.403 Waivers.

Paragraph (a) provides for a procedure by which any State regulatory authority or nonregulated electric utility may apply for a waiver from the application of any of the requirements of Subpart C other than §292.302. (Section 292.302(d) has been revised to permit a State regulatory authority or nonregulated utility to adopt a substitute method for the provision of system cost data without prior Commission approval.)

Paragraph (b) provides that the Commission will grant such a waiver only if the applicant can show that compliance with any of the requirements is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210 of PURPA.

This section is included in recognition of the need for the Commission to afford flexibility to the States and nonregulated utilities to implement the Commission's rules under section 210.

Several comments suggested that the Commission set forth procedures for considering applications for waivers which would allow formal participation by qualifying facilities in a public hearing. The commission notes that interested parties would be given an opportunity to be heard in any proceeding it conducts to determine whether or not a waiver should be granted

Subpart F -- Exemption of Qualifying Small Power Production and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§292.601 Exemption of qualifying facilities from the Federal Power Act.

Section 210(e) of PURPA states that the Commission shall prescribe rules under which qualifying facilities are exempt, in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, from the State laws and regulations respecting the rates, or respecting the financial or organization regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. As noted in the Staff Discussion Paper, the Congress intended the Commission to make liberal use of its exemption authority in order to remove the disincentive of utility-type regulation. The Commission believes that broad exemption is appropriate.

Section 210(e)(2) of PURPA provides that the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from these laws. An exception is made for small power production facilities using biomass as a primary energy source. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State laws and regulations but may not be exempted from the Federal Power Act. The Commission will establish procedures for the determination of rates for these facilities in a separate proceeding.

Paragraph (a) sets forth those facilities which are eligible for exemption. Paragraph (b) provides that facilities described in

paragraph (a) shall be exempted from all but certain specified sections of the Federal Power Act.

Section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from any license or permit requirement under Part I of the Federal Power Act. Accordingly, no qualifying facilities will be exempt from Part I of the Federal Power Act. The Commission recently issued simplified procedures for obtaining water power licenses for hydroelectric projects of 1.5 megawatts or less, and has issued proposed regulations to expedite licensing of existing facilities.[21]

The Commission believes cogeneration and small power production facilities could be the subject of an order under section 202(c) of the Federal Power Act requiring them to provide energy if the Economic Regulatory Administration determines that an emergency situation exists. Because application of this section is limited to emergency situations and is not affected by the fact that a facility attains qualifying status or engages in interchanges with an electric utility, the Commission notes that qualifying facilities will not be exempted from section 202(c) of the Act.

Furthermore, in response to comment, the Commission has revised this paragraph to provide that qualifying facilities are not exempt from sections 210, 211, and 212 of the Federal Power Act, as required by section 210(e)(3)(B) of PURPA.

Sections 203, 204, 205, 206, 208, 301, 302, and 304 of the Federal Power Act reflect traditional rate regulation or

---

[21] See Order No. 11, Simplified Procedures for Certain Water Power Licenses. Docket No. RM79-9, issued September 5, 1978, and Application for License for Major Projects--Existing Dam, Docket No. RM79-36, 44 FR 24095 (April 21, 1979).

regulation of securities of public utilities. The Commission has determined that qualifying facilities shall be exempted from these sections of the Federal Power Act.

Section 305(c) of the Act imposes certain reporting requirements on interlocking directorates. The Commission believes that any person who otherwise is required to file a report regarding interlocking positions should not be exempted from such requirement because he or she is also a director or officer of a qualifying facility.

Finally, the enforcement provisions of Part III of the Federal Power Act will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organization. Only cogeneration facilities and small power production facilities of 30 megawatts or less may be exempted from both of these laws, with the exception that any qualifying small power production facility (i.e., up to 80 megawatts) using biomass as a primary energy source can be exempted from these laws.

The Commission has determined that where a qualifying facility is subjected to more stringent regulation than other companies solely by reason of the fact that it is engaged in the production of electric energy, these more stringent requirements should be eased through exemption of qualifying facilities. By

excluding any qualifying facility from the definition of an "electric utility company" under section 2(a)(3) of the Public Utility Holding Company Act of 1935, such facilities would be removed from Public Utility Holding Company Act regulation which is applied exclusively to electric utility companies. Moreover, by excluding qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric production by their subsidiaries. The Commission therefore believes that in order to encourage cogeneration and small power production it is necessary to exempt cogenerators and small power producers from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities.

Accordingly, paragraph (b) states that no qualifying facility shall be considered to be an "electric utility company", as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. §79b(a)(3).

Section 210(e) of PURPA states that qualifying facilities which may be exempted from the Public Utility Holding Company Act may also be exempted from State laws and regulations respecting the rates or financial organization of electric utilities.

The Commission has decided to provide a broad exemption from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

The Commission believes that such broad exemption is necessary to encourage cogeneration or small power production. Accordingly, subparagraph (c)(1) provides that any qualifying facility shall be exempt from State laws and regulations respecting

rates of electric utilities, and from financial and organizational regulation of electric utilities. Several commenters noted that this section might be interpreted as exempting qualifying facilities from state laws or regulations implementing the Commission's rules, under section 210(f) of PURPA. In order to clarify that qualifying facilities are not to be exempt from these rules, the Commission has added subparagraph (c)(2) prohibiting any exemptions from State laws and regulations promulgated pursuant to Subpart C of these rules.

Some commenters indicated that §292.301(b)(1) might be interpreted as prohibiting a State from reviewing contracts for purchases. These commenters stated that, as a part of a State's regulation of electric utilities, a State regulatory authority needs to be able to review contracts entered into by electric utilities it regulates.

These rules, and the exemptions being provided by these rules, are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities. Such authority may continue to be exercised if consistent with the terms, policies and practices under sections 210 and 201 of PURPA and this Commission's implementing regulations. If the authority or its exercise is in conflict with these sections of PURPA or the Commission's regulations thereunder, the State must yield to the Federal requirements. The Commission does not believe it possible or advisable to attempt to establish more precise guidelines than these. Accordingly, States which have questions in this regard should seek an interpretive ruling from the Commission's General Counsel.

Subparagraph (c)(3) provides that, upon request of a State regulatory authority or nonregulated electric utility, the Commission may limit the applicability of the broad exemption from the State laws. This provision is intended to add flexibility to the exemption.

The Commission perceives that there may be instances in which a qualifying facility would wish to have an interpretation of whether or not it is subject to a particular State law in order to remove any uncertainty. Under subparagraph (c)(4), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §2601, et seq., Energy Supply and Environmental Coordination Act, 15 U.S.C. §791 et seq., Federal Power Act, as amended, 16 U.S.C. §792 et seq., Department of Energy Organization Act, 42 U.S.C. §7101 et seq., E.O. 12009, 42 Fed. Reg. 46267)

* * *

that QFs could be paid, under certain conditions, more than the full avoided capacity cost per kw which, for the sake of convenience, the Commission converted to a rate which was based on cents per kwh. The order provided that if QF facilities operate as reliably as Vepco's own generating units, the operators will be entitled to receive full avoided capacity payments from Vepco. However, consistent with our view that no QF should receive more than full avoided costs, we find it appropriate to insert at the appropriate point in Schedule 19 the limiting language Vepco suggested in Attachment A to its Petition. This language will eliminate the potential for any QF to receive capacity payments in excess of full avoided capacity costs.

In conclusion, the Commission finds that the petition should be denied, with the exception of the matter discussed in the immediately preceding paragraph. Accordingly,

IT IS THEREFORE, ORDERED that the Petition for Reconsideration is denied, except as noted.

APPENDIX N

Rule 29.1 Statement

North Carolina Power is the North Carolina operating division of Virginia Electric and Power Company in North Carolina. Virginia Electric and Power Company is a wholly-owned subsidiary of Dominion Resources, Inc. Virginia Electric and Power Company has no non-wholly-owned subsidiaries.

Supreme Court, U.S.
FILED
JUL 17 1995
CLERK

(3)

No. 94-1868

IN THE
Supreme Court of the United States
OCTOBER TERM, 1995

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel*,
UTILITIES COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

BRIEF FOR THE EDISON ELECTRIC INSTITUTE AS AMICUS CURIAE IN SUPPORT OF THE PETITION

EDWARD BERLIN *
J. PHILLIP JORDAN
ROBERT V. ZENER
SWIDLER & BERLIN, CHARTERED
3000 K Street, N.W.
Suite 300
Washington, D.C. 20007
(202) 424-7500
* *Counsel of Record*

July 17, 1995

WILSON - EPES PRINTING CO., INC. - 789-0096 - WASHINGTON, D.C. 20001

BEST AVAILABLE COPY

18pp

QUESTION PRESENTED

Under the Supremacy Clause, "States may not bar regulated utilities from passing through to retail consumers FERC-mandated wholesale rates." *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 372 (1988). The Public Utility Regulatory Policies Act of 1978 ("PURPA"), as implemented by regulations of the Federal Energy Regulatory Commission ("FERC"), delegates to state utility commissions the federal authority, previously exercised by FERC, to establish wholesale rates for power sold by cogeneration facilities. 16 U.S.C. § 824a-3(f).

The question in this case is whether the Supremacy Clause prohibits a state utility commission from barring a multi-state utility from passing through to retail conumers wholesale rates previously established for that utility by another state utility commission exercising the federal authority delegated to it under PURPA.

TABLE OF CONTENTS

	Page
QUESTION PRESENTED	i
TABLE OF AUTHORITIES	iv
INTEREST OF AMICUS CURIAE	1
STATEMENT	2
REASONS FOR GRANTING THE WRIT	6
CONCLUSION	12

TABLE OF AUTHORITIES

CASES: Page

American Paper Institute v. American Electric Power Service Corp., 461 U.S. 402 (1983) 3
Arkansas Elec. Co-op v. Arkansas Public Service Comm'n, 461 U.S. 375 (1983) 2
City of Milwaukee v. Illinois & Michigan, 451 U.S. 304 (1981) 6, 9
FPC v. Southern California Edison Co., 376 U.S. 205 (1964) 2, 7
Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742 (1982) 3, 6, 8
Hodel v. Virginia Surface Mining & Reclamation Ass'n, 452 U.S. 264 (1981) 6
International Paper Co. v. Ouellette, 479 U.S. 481 (1987) 6
Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988) ..... i, 2, 5-9
Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953 (1986) 2, 5-7, 9, 11
Niagara Mohawk Power Corporation v. Federal Energy Regulatory Commission, D.C. Cir. Nos. 95-1222, 95-1223 (filed April 21, 1995) 8, 9
Niagara Mohawk Power Corporation v. Federal Energy Regulatory Commission et al., N.D.N.Y. No. 95-CV-634 (filed May 11, 1995) 9
Public Utility Commission of Rhode Island v. Attleboro, 273 U.S. 83 (1927) 2

STATUTES:

16 U.S.C. §§ 796(17), (18), 824a-3(a), (b) 3
16 U.S.C. § 824a-3(a) 9
16 U.S.C. § 824a-3(f) ..... i, 3, 8, 10
16 U.S.C. § 824a-3(h) 10
Public Utility Act of 1935, ch. 687, 49 Stat. 803, Title II 2
Federal Power Act of 1920, ch. 285, 41 Stat. 1063 .. 2
Public Utility Regulatory Policies Act of 1978 ("PURPA"), P.L. 95-617, 92 Stat. 3117 2

TABLE OF AUTHORITIES—Continued

	Page
REGULATIONS:	
18 C.F.R. § 292.303(a)	9
18 C.F.R. § 292.304(a)(2)	3
18 C.F.R. §§ 385.214(a), 385.1306	10
18 C.F.R. § 385.1302(a)	10
REGULATORY PROCEEDINGS:	
Connecticut Light and Power Company, 70 FERC ¶ 61,012, *reconsideration denied*, 71 FERC ¶ 61,035 (1995)	7, 8
Orange and Rockland Utilities, Inc., Rockland Electric Company and Pike County Light & Power Company, 70 FERC ¶ 61,014, *reconsideration denied*, 71 FERC ¶ 61,034 (1995)	8
MISCELLANEOUS:	
60 F.R. 17662 (April 7, 1995)	12
Va. Code § 12.1-39	9
Petitioner's Appendix	*passim*

IN THE

Supreme Court of the United States

OCTOBER TERM, 1995

No. 94-1868

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel*,
UTILITIES COMMISSION,
Respondent.

On Petition for a Writ of Certiorari to the Supreme Court of North Carolina

---

BRIEF FOR THE EDISON ELECTRIC INSTITUTE AS AMICUS CURIAE IN SUPPORT OF THE PETITION

INTEREST OF AMICUS CURIAE

The Edison Electric Institute ("EEI") is the association of investor-owned electric utilities in the United States and industry affiliates worldwide. EEI's members serve 99 percent of all customers served by the investor-owned segment of the U.S. industry. As of December 31, 1993, they generated approximately 79 percent of all the electricity in the country and serviced 76 percent of all ultimate customers in the nation. Thirty-eight of the

member utilities of EEI are unified corporations serving consumers in more than one state, with fifteen of those companies subject to the jurisdiction of three or more state utility commissions. As such, the membership of EEI has a vital interest in the question presented by this litigation.

STATEMENT

1. In *Public Utility Commission of Rhode Island v. Attleboro*, 273 U.S. 83 (1927), this Court held that state jurisdiction over the establishment of electric rates does not extend to interstate wholesale transactions, that is, to sales of electric power for resale. In response to the "regulatory gap" thereby created, Congress enacted the Public Utility Act of 1935, ch. 687, 49 Stat. 803, Title II of which amended the Federal Power Act of 1920, ch. 285, 41 Stat. 1063, to confer upon the Federal Power Commission, now the Federal Energy Regulatory Commission ("FERC"), exclusive jurisdiction over rates for most wholesale power transactions. Where FERC has authority to establish wholesale rates, State authority is preempted. *See Arkansas Elec. Co-op v. Arkansas Public Service Comm'n*, 461 U.S. 375 (1983); *FPC v. Southern California Edison Co.*, 376 U.S. 205 (1964). And, by operation of the Supremacy Clause, state regulatory commissions, when exercising their "undoubted jurisdiction over retail rates," are obliged to permit full flow-through of the wholesale charges approved by FERC. *Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953, 970 (1986); *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 371-2 (1988).

2. Prior to the enactment of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), P.L. 95-617, 92 Stat. 3117, FERC had exclusive authority to establish rates for power sold at wholesale, including power from entities that were to become qualifying facilities under PURPA. With the enactment of PURPA, Congress delegated to state regulatory commissions, acting pursuant to

rules to be promulgated by the FERC, the responsibility to establish the rates to be paid by utilities for wholesale purchases from qualifying facilities.[1] FERC's rules provided, among other things, that utilities must purchase power from qualifying facilities at a rate equal to the utilities' full "avoided costs."[2] PURPA imposed on each state utility commission the responsibility to implement FERC's rules for each utility within its jurisdiction. 16 U.S.C. § 824a-3(f)(1). This includes the responsibility to determine, or adjudicate disputes concerning, what wholesale rates must be paid under the federal "avoided cost" requirement. *Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 742, 759-61 (1982).

3. Petitioner, North Carolina Power, is the unincorporated division of Virginia Electric and Power Company ("VEPCO") that does business in North Carolina. It accounts for approximately five percent of total company retail revenues. The balance, or approximately ninety-five percent, comes from Virginia Power, the unincorporated VEPCO division in Virginia.

4. On November 12, 1987, Ultra Cogen Systems, Inc. ("Ultra Cogen"), a qualifying facility under PURPA, invoked the jurisdiction of the Virginia State Corporation Commission ("VSCC"), seeking an order directing the VEPCO system to purchase the output of nine projects proposed by Ultra Cogen. The VSCC is the state regulatory commission responsible for the regulation of electric utilities doing business in Virginia. As such, it is the state agency in Virginia that has been delegated responsibility for implementing FERC's PURPA rules. In a

---

[1] "Qualifying facilities" refers to certain cogeneration and small power production facilities that, under PURPA, have an absolute right to sell their output to utilities. 16 U.S.C. §§ 796(17), (18), 824a-3(a), (b).

[2] 18 C.F.R. § 292.304(a)(2). FERC's "avoided cost" regulation was sustained by this Court in *American Paper Institute v. American Electric Power Service Corp.*, 461 U.S. 402 (1983).

series of orders issued between April 27 and November 18, 1988, the VSCC directed the VEPCO system to purchase the output of four Ultra Cogen facilities, all located in Virginia. Pet. App. 184a, 191a. Purchase was required at "avoided cost payments . . . based on Virginia Power's costs of constructing and operating Chesterfield Unit No. 7," a unit that VEPCO had earlier identified as "the prototype of any new capacity to be built by the Company through the mid-1990's, and perhaps beyond." Pet. App. 172a. VEPCO had objected to the VSCC's calculating its avoided costs based on its prototype unit, contending that lower priced alternatives would be available through a competitive solicitation. Pet. App. 173a. Judicial review of the VSCC's order requiring the purchase and specifying the pricing terms was not sought.

5. On July 31, 1992, North Carolina Power applied to its state regulatory commission, the North Carolina Utilities Commission ("NCUC"), for permission to increase its retail rates. Among the costs North Carolina Power sought to recover was the portion of the payments made to Ultra Cogen that represents the allocable share of the capacity of Ultra Cogen's projects used to provide service to that portion of the VEPCO system within North Carolina. The NCUC, while not taking issue with the purchase of capacity from Ultra Cogen, concluded that it would have determined North Carolina Power's costs to purchase the Ultra Cogen power to be lower than the costs determined by the VSCC for the overall VEPCO system. Accordingly, the NCUC denied recovery of the portion of the payment it found to be excessive—a disallowance of $1.39 million per year.

6. On appeal, the Supreme Court of North Carolina, in a 5 to 2 decision, upheld that disallowance. Recognizing that the avoided cost rates established by a state regulatory commission are "determined under federal rules implemented by each state for utilities subject to their ratemaking authority" (Pet. App. 6a), the Court nevertheless upheld the NCUC's right to disagree with the

VSCC's determination of avoided costs and to deny North Carolina Power recovery in retail rates based on that disagreement. It did so notwithstanding its "recogn[ition] that inconsistent determinations of avoided costs by the VSCC and the [NCUC] may burden NC Power," a burden that it dismissed as "a necessary consequence of doing business in more than one state." Pet. App. 11a. Two Justices, in dissent, expressed the view that:

> . . . [W]hen VSCC set the price NC Power must pay Ultra Cogen for the wholesale power at issue here, the VSCC was implementing federal law and making a determination affecting wholesale power in interstate commerce. The VSCC was making a determination which, but for the provisions of PURPA, would have been made exclusively by FERC; that determination was the functional and legal equivalent of an order by the FERC setting the price.
>
> * * *
>
> No one questioned the jurisdiction of the VSCC to hear the dispute or to enter its decision. Ultra Cogen went to the VSCC rather than the NCUC because the wholesale sales at issue were to take place in Virginia. Once the VSCC entered its ruling, the obligation of NC Power to purchase wholesale power from Ultra Cogen and the price of that wholesale power were established by federal law. From that point on, neither the NCUC nor any other state agency was free to establish a different price that NC Power must pay Ultra Cogen for the wholesale power, even though it was to be resold in North Carolina.

Pet. App. 14a-15a, 18a-19a. The dissenting Justices concluded "that the determination of the VSCC had a preemptive effect equivalent to the preemptive effect of FERC orders establishing wholesale rates" and, under *Nantahala* and *Mississippi Power & Light, supra*, "the action of the NCUC was preempted by PURPA and by the essentially federal act of the VSCC . . . ." *Id.* at 9-10.

REASONS FOR GRANTING THE WRIT

The North Carolina decision, if permitted to stand, would severely hamper the effectiveness of the Congressional delegation to state utility commissions of authority to establish the level of wholesale rates for power sold by qualifying facilities under PURPA. As the Court recognized in *Nantahala* and *Mississippi Power & Light*, the establishment of wholesale rates cannot be fully effective unless there is an assurance that they will be passed through to retail consumers. Under the North Carolina decision, a state commission setting wholesale rates under PURPA for a multi-state utility will not have that assurance.

PURPA establishes a scheme of "co-operative federalism" that allows the states to make federally binding decisions structured for their own particular needs. *Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 742, 767 (1982), quoting *Hodel v. Virginia Surface Mining & Reclamation Ass'n*, 452 U.S. 264, 289 (1981). In this respect, PURPA "resembles a number of other federal statutes . . . ." *Hodel, supra*, 452 U.S. at 290 and n.30 (citing cases). Unless it is made clear that the decisions of state regulatory agencies exercising delegated federal authority are as binding on other states as the decisions of a federal agency would be, the usefulness of this form of co-operative federalism will be severely diminished in any situation involving a multi-state impact. This Court has held under the Clean Water Act that the decision of a state agency establishing federal discharge limits pursuant to delegated federal authority cannot be second-guessed by courts in a downstream state. *City of Milwaukee v. Illinois & Michigan*, 451 U.S. 304 (1981).[3]

---

[3] Courts in the downstream state may entertain suits based on state law, since the Clean Water Act, unlike PURPA, has a savings clause preserving state common-law remedies. *International Paper Co. v. Ouellette*, 479 U.S. 481, 485, 497 (1987). However, the

Similarly under PURPA, a state's decision under delegated federal authority, to be fully effective, must be as binding as the decision of a federal agency would be.

1. The North Carolina decision is in substantial tension with this Court's decisions in *Nantahala* and *Mississippi Power & Light*. In each of those holdings, the Court made clear that state regulatory commissions, though exercising plenary authority over the establishment of retail electric rates, must give full effect to the rate determinations of the FERC made within its area of exclusive authority. This case presents the logical next question—whether a state commission must accord similar effect to wholesale power rates established by a neighboring state pursuant to a delegation of federal authority.

2. There can be no dispute that the charges North Carolina refused to permit to be recovered in retail rates are charges for wholesale power sales in interstate commerce.[4] Those are the only power sale transactions covered by PURPA and, but for the delegation, the VSCC could not have exercised jurisdiction over the Ultra Cogen-VEPCO transaction.[5] It exercised jurisdiction be-

---

downstream state may not apply federal law to the discharge, if the upstream state in which the discharger is located has established federal limits pursuant to delegated authority. *City of Milwaukee, supra.*

[4] The interstate character of the Ultra Cogen-VEPCO/North Carolina Power transaction is apparent—the facilities are located in Virginia and the portion of the power at issue is consumed in North Carolina. It has long been settled that federal jurisdiction over wholesale power sales, with minor exceptions not relevant here, is pervasive and exclusive. *FPC v. Southern California Edison Co.*, 376 U.S. 205 (1964).

[5] In a recent declaratory order, the FERC observed:

> PURPA gave the states a specific but limited role to set wholesale rates pursuant to the statute and the Commission's regulations—a role that in most instances they would not otherwise

cause federal law so required,[6] and it exercised jurisdiction that, absent the delegation, would have been FERC's alone to discharge.

Neither the NCUC nor the North Carolina Supreme Court take issue with the jurisdiction of the VSCC over the price to be paid by VEPCO, and by extension by its North Carolina division, to Ultra Cogen. Rather, each assumes that notwithstanding that exercise of federal jurisdiction by Virginia, North Carolina remains free to disagree with Virginia's determination of price. But the VSCC's jurisdiction to make the wholesale rate determination included jurisdiction to make what third parties—such as the NCUC—might consider to be a mistake. The VSCC's decision, whether or not it resulted in the best price for retail customers, was an exercise of plenary jurisdiction under a federal statute, which the NCUC "may not alter . . . by substituting [its] own determination[] of what would be just and fair." *Mississippi Power & Light, supra,* 487 U.S. at 371.[7]

---

have had since QF sales primarily are sales for resale in interstate commerce.

Connecticut Light & Power Co., 71 FERC ¶ 61,035, p. 61,153 (1995).

[6] *Mississippi, supra,* 456 U.S. at 759-61.

[7] There is no occasion in this case to decide whether the VSCC, as part of its obligation under section 210(f) of PURPA to "implement" FERC's rules, has an obligation to reopen a prior decision that violated the avoided cost limitation established by PURPA. 16 U.S.C. § 824a-3(f). FERC has ruled that a state has no such obligation, even where FERC's interpretation of applicable law makes it plain that the prior state decision was in violation of that limitation. *Connecticut Light and Power Company,* 70 FERC ¶ 61,012, *reconsideration denied,* 71 FERC ¶ 61,035 (1995); *Orange and Rockland Utilities, Inc., Rockland Electric Company and Pike County Light & Power Company,* 70 FERC ¶ 61,014, *reconsideration denied,* 71 FERC ¶ 61,034 (1955). Suits challenging this ruling have been filed. *Niagara Mohawk Power Corporation v. Federal Energy Regulatory Commission,* D.C. Cir. Nos.

Nor can North Carolina draw comfort from the limited reservation of state authority—suggested by this Court in *Nantahala* and *Mississippi Power & Light*—to determine that a utility "purchase[d] unnecessary quantities of high cost power, even at FERC-approved rates, if it had the legal right to refuse to buy that power." *Mississippi*, 487 U.S. at 373-4; *Nantahala*, 476 U.S. at 972. As in *Mississippi*, where that possible reservation was foreclosed by the FERC order directing the utility "to procure the particular quantity of high-priced" power (487 U.S. at 474), here PURPA mandated that VEPCO (including its North Carolina division, North Carolina Power) purchase the entire output tendered by Ultra Cogen. 16 U.S.C. § 824a-3(a); 18 C.F.R. § 292.303(a).

Had the wholesale rate charged by Ultra Cogen been fixed in a non-PURPA transaction, the NCUC would have been restricted to seeking redress in a review action from that FERC determination. It would not have been free to exercise "self-help." The current situation contains a parallel. Apart from the judicial review procedures to which decisions of the VSCC ordinarily are subject,[8] Congress, in PURPA, provided an additional jurisdictional path for challenges to state implementation of the statute's avoided cost limitation. The FERC may enforce the requirements of its rules—including the limitations in its pricing rules—against "any State regulatory authority"

95-1222, 95-1223 (filed April 21, 1995); *Niagara Mohawk Power Corporation v. Federal Energy Regulatory Commission et al.*, N.D.N.Y. No. 95-CV-634 (filed May 11, 1995). The issue involved in those cases is neither presented by this Petition nor affects its "ripeness." If FERC is in error, and a challenge to the determination of the VSCC is yet available, that is the path the NCUC is obliged to pursue. If, conversely, FERC is correct and VEPCO no longer can be relieved of the VSCC's determination of the federal rate, *Nantahala* and *Mississippi Power & Light* require the NCUC to give that rate full effect.

[8] Decisions of the VSCC are directly appealable to the Virginia Supreme Court. Va. Code § 12.1-39.

by initiating an action in the appropriate federal district court. 16 U.S.C. § 824a-3(h)(2)(A). Any electric utility or qualifying facility may request that FERC initiate such an action and, if FERC declines to do so within 60 days, "may bring an action in the appropriate United States district court to require such State regulatory authority . . . to comply with [FERC's] requirements, and such court may issue such injunctive or other relief as may be appropriate." 16 U.S.C. § 824a-3(h)(2)(B). The NCUC surely could have required North Carolina Power to initiate such a proceeding before FERC, in which NCUC could have intervened to protect its interests.[9]

PURPA's structure allows any state potentially affected by a wholesale rate proceeding in another state to protect its interests without the necessity of permitting the type of disruptive collateral challenge countenanced by the decision below. PURPA requires the state to provide "notice and opportunity for public hearing" in establishing wholesale rates under the Act. 16 U.S.C. § 824a-3 (f)(1). Given that requirement, and in the event that the binding nature of such determinations on other states becomes a problem, FERC could require every state commission to notify the commissions of other states potentially affected by a wholesale rate determination under PURPA.[10] Alternatively, the NCUC could require North Carolina Power to notify it of pending Virginia proceedings.

3. The NCUC would dismiss the "trapping" of costs that results from its decision as no more than "an inevitable consequence of doing utility business across state

---

[9] FERC rules provide that any State Commission becomes a party to any proceeding upon filing a timely notice of intervention. 18 C.F.R. §§ 385.214(a)(2), 385.1306.

[10] FERC requires notice to the commissions of all affected states in connection with its proceedings under the Federal Power Act and the Natural Gas Act. 18 C.F.R. § 385.1302(a).

lines" where, for example, a utility may be "caught in the middle" between different utility commissions' use of "a different cost allocation methodology . . . for purposes of allocating production costs between states." Pet. App. 75a. The analogy is not at all apt. It may well be "inevitable" that a utility will be "caught in the middle" where each state regulatory commission is discharging its exclusive jurisdiction, and, absent each commission's ability to do so, its authority would be infringed. The cost of utility-owned production plant, for example, may be allocated differently by each state so that the utility recovers less than 100% of its costs. But in the case at bar, no costs subject to disparate recovery through lawful exercise of North Carolina jurisdiction are involved. Once the wholesale rate for Ultra Cogen's power was duly determined by the VSCC under federal law, North Carolina had no jurisdiction to refuse to allow a pass-through on the basis of its disagreement with the VSCC.

Once the wholesale rate is approved by a state exercising delegated federal authority, it is the contemplation of PURPA that the qualifying facility is in a position to proceed with financing and project development. However, the North Carolina decision makes that less likely. If that decision is allowed to stand, the result will be, as pointed out in *Nantahala*, to require the utility to "pretend that it is paying less for the power it receives from [its wholesale supplier], under agreements not subject to NCUC's jurisdiction, than is in fact the case." *Nantahala, supra*, 476 U.S. at 971. As a result, multistate utilities will need prior approval of the price from each jurisdiction where the power from qualifying facilities is resold. If pricing approval were required from the state commission in each state with retail customers receiving a portion of the power, delay could be interminable. Further, because the avoided cost calculation is inherently judgmental, the likelihood that two or more state commissions would fix the same purchase price borders on the whimsical. Instead, the likelihood that the initial determination

of wholesale rates under PURPA will be undercut by another state will deprive that determiation of binding effect.

If the decision of the North Carolina Supreme Court is allowed to stand, state commissions in situations comparable to NCUC's relationship to North Carolina Power may feel compelled to follow the example that now has been set. Every multi-state utility that has been required to purchase power from a qualifying facility is now exposed to added financial risk. It is a risk that is poorly timed. The investor-owned utility industry already is struggling with the complexities of the transition to a more competitive, and increasingly multijurisdictional, environment. *See, e.g.*, 60 F.R. 17662 (April 7, 1995). The industry, and its competitive evolution, are poorly served by the trapped costs created by the decision below.

CONCLUSION

For all of the aforesaid reasons, the petition by North Carolina Power for a writ of certiorari should be granted.

Respectfully submitted,

EDWARD BERLIN *
J. PHILLIP JORDAN
ROBERT V. ZENER
SWIDLER & BERLIN, CHARTERED
3000 K Street, N.W.
Suite 300
Washington, D.C. 20007
(202) 424-7500
* *Counsel of Record*

July 17, 1995

Supreme Court, U.S.
FILED
JUL 17 1995
CLERK

No. 94-1868

In the
Supreme Court of the United States
October Term, 1994

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

Petition for a Writ of Certiorari from the Supreme Court of North Carolina

BRIEF IN OPPOSITION

Gisele L. Rankin, Staff Attorney*
A. W. Turner, Jr., Staff Attorney

Public Staff - North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, North Carolina 27611
(919) 733-6110

**Counsel of Record*

BEST AVAILABLE COPY

QUESTIONS PRESENTED

1. Does a state violate the Supremacy Clause when, in the exercise of its retail ratemaking authority, it disallows QF capacity costs set in excess of avoided costs by another state, when that other state was acting pursuant to its laws and policies and not in accordance with § 210 of PURPA?

2. Does a state violate the Commerce Clause when, in the exercise of its retail ratemaking authority, it disallows QF capacity costs set in excess of avoided costs by another state, when that other state was acting pursuant to its laws and policies and not in accordance with § 210 of PURPA?

TABLE OF CONTENTS

Page

QUESTIONS PRESENTED i

TABLE OF AUTHORITIES vi

ADDITIONAL STATUTORY AND REGULATORY PROVISIONS 2

STATEMENT OF THE CASE 2

A. Introduction 2

B. Proceedings Below:

1. The Virginia Proceedings 3

2. The North Carolina Utilities Commission Proceeding 6

3. The North Carolina Supreme Court's Decision 8

REASONS WHY THE WRIT SHOULD NOT BE GRANTED 11

I. THE NORTH CAROLINA SUPREME COURT'S OPINION IS CONSISTENT WITH THIS COURT'S SUPREMACY CLAUSE DECISIONS 11

A. Introduction 11

TABLE OF CONTENTS - Continued

Page

B. This Court's Supremacy Clause Decisions and the Requirements of § 210 of PURPA 11

C. The Consistency of the North Carolina Supreme Court's Opinion With Federal Law 16

D. Conclusion 22

II. THE NORTH CAROLINA SUPREME COURT'S OPINION IS CONSISTENT WITH THE PURPOSES AND GOALS OF § 210 OF PURPA, AND ANY FEDERAL ISSUES INVOLVED IN THIS CASE ARE NOT OF CURRENT OR GENERAL INTEREST 23

III. THE NORTH CAROLINA SUPREME COURT'S OPINION IS CONSISTENT WITH THIS COURT'S COMMERCE CLAUSE DECISIONS 26

CONCLUSION 29

TABLE OF CONTENTS - Continued

Page

APPENDICES

APPENDIX A

Additional Statutory and Regulatory Provisions 1a

APPENDIX B

Petition of Ultra Cogen Systems, Inc.,
for Arbitration (November 12, 1987) 5a

APPENDIX C

Opinion and Final Order of the Virginia State
Corporation Commission (February 13, 1990) . . . 11a

TABLE OF AUTHORITIES

UNITED STATES COURT CASES Page

American Paper Institute v. American Electric Power Service Corporation, 461 U.S. 402 (1983) . . 18
Arkansas Electric Cooperative Corporation v. Arkansas Public Service Commission, 461 U.S. 375 (1983) 12, 26, 27, 28
Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742 (1982) 14
Florida Lime & Avocado Growers v. Paul, 373 U.S. 132 (1963) 12
Hines v. Davidowitz, 312 U.S. 52 (1941) 12
Illinois Natural Gas Company v. Central Illinois Public Service Company, 314 U.S. 498 (1942) 26
Middle South Energy v. Arkansas Public Service Commission, 772 F.2d 404 (8th Cir. 1985), *cert. denied*, 474 U.S. 1102 (1986) 28
Mississippi Power & Light Company v. Mississippi ex rel. Moore, 487 U.S. 354 (1988) 9, 17, 22, 28
Missouri ex rel. Barrett v. Kansas Natural Gas Company, 265 U.S. 298 (1924) 12
Munn v. Illinois, 94 U.S. 113 (1877) 13
Nantahala Power & Light Company v. Thornburg, 476 U.S. 953 (1986) . 9, 16, 17, 22, 28
Pacific Gas & Electric Company v. State Energy Resources Conservation & Development Commission, 461 U.S. 190 (1983) 13
Pike v. Bruce Church, Inc., 397 U.S. 137 (1970) 27
Public Utilities Commission v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927) 12, 26
Rice v. Santa Fe Elevator Corporation, 331 U.S. 218 (1947) 12, 13

TABLE OF AUTHORITIES - Continued

Page

Western & Southern Life Insurance Company v. Board of Equalization, 451 U.S. 648 (1981) 26
Wyoming v. Oklahoma, 502 U.S. 437 (1992) 14

FEDERAL ADMINISTRATIVE DECISIONS

Connecticut Light & Power Company, 70 FERC ¶ 61,012 (1995) 18, 24
Doswell Limited Partnership, 50 FERC ¶ 61,251, 110 P.U.R.4th 261 (1990) . . 6, 17
Middle South Services, Inc., 33 FERC ¶ 61,408, 71 P.U.R.4th 580 (1985) 18
Orange and Rockland Utilities, 43 FERC ¶ 61,067, 92 P.U.R.4th 1 (1988) . 9, 18, 19, 22, 23

UNITED STATES CONSTITUTION

Art I, sec. 8, cl. 3 (Commerce Clause) 8, 26, 27, 28
Art VI, cl. 2 (Supremacy Clause) 11, 22, 23

UNITED STATES STATUTES

PUHCA, 15 U.S.C. § 79 to 79z-6 (1988 & Supp. V 1993) 15, 16, 24
Federal Power Act, 16 U.S.C. §§ 791-825u (1988 & Supp. V 1993) 6, 13, 24
16 U.S.C. § 824(a) (1988) 2, 13
§ 210 of PURPA, 16 U.S.C. § 824a-3 (1988 & Supp. V 1993) 3, 24
16 U.S.C. § 824a-3(a) (1988) 15
16 U.S.C. § 824a-3(b) (1988) 2, 15
16 U.S.C. § 824a-3(e) (1988 & Supp. V 1993) 2, 15
16 U.S.C. § 824(b)(1) (1988) 2, 13

TABLE OF AUTHORITIES - Continued

Page

16 U.S.C. § 824(d) (1988) 13
Pub. L. No. 102-486, 106 Stat. 2776 24

REGULATIONS

18 C.F.R. § 292.101(b)(6) (1995) 2, 15
18 C.F.R. § 292.304 (1995) 15
18 C.F.R. § 292.304(b)(5) (1995) 21
18 C.F.R. § 292.304(d)(2) (1995) 2, 20, 21
18 C.F.R. §§ 292.601-.602 (1995) 2, 16
Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, 45 Fed. Reg. 12,214 (1980) . 16, 18, 21

STATE ADMINISTRATIVE DECISION

Doswell Limited Partnership, 110 P.U.R.4th 273 (Va.St.Corp.Comm'n 1990) 6
Pennsylvania Electric Company, 89 P.U.R.4th 402 (Pa.Pub.Util.Comm'n 1988) . . . 21

OTHER

H.R.Rep.No. 1318, 74th Cong., 1st Sess., 8 (1935) 14
H.R.Rep.No. 5423, 74th Cong., 1st Sess., 385 (1935) 14
S. 708, 104th Cong., 1st Sess. (1995) 24
National Regulatory Research Institute, *A Synopsis of The Energy Policy Act of 1992: New Tasks for State Public Utility Commissions* (1993) 24

No. 94-1868

In the

Supreme Court of the United States

October Term, 1994

NORTH CAROLINA POWER,

Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,

Respondent.

Petition for a Writ of Certiorari from the Supreme Court of North Carolina

---

BRIEF IN OPPOSITION

Respondent Public Staff - North Carolina Utilities Commission respectfully requests that this Court deny the petition for a writ of certiorari seeking review of the decision of the Supreme Court of North Carolina in this case.

ADDITIONAL STATUTORY AND REGULATORY PROVISIONS

The pertinent texts of the statutes and regulations listed below are set out verbatim in the Appendix at 1a-4a.

The following provisions of the Federal Power Act:

16 U.S.C. § 824(a) (1988).

16 U.S.C. § 824a-3(b) (1988).

16 U.S.C. § 824a-3(e)(1) (1988).

16 U.S.C. § 824(b)(1) (1988).

The following provisions of the Regulations Under the Public Utility Regulatory Policies Act of 1978:

18 C.F.R. § 292.101(b)(6) (1995).

18 C.F.R. § 292.304(d)(2) (1995).

18 C.F.R. § 292.601(a)-(c) (1995).

STATEMENT OF THE CASE

A. Introduction

The Statement of the Case set forth in the Petition of Virginia Electric & Power Company, d/b/a North Carolina Power in North Carolina (Petitioner), contains a summary of its argument in addition to its statement of the facts of this case. Respondent Public Staff will address Petitioner's arguments in subsequent sections of this brief. This counterstatement of the case contains a more accurate and complete statement of the facts and the procedural history of this case.

B. Proceedings Below

1. *The Virginia Proceedings*

The arbitration proceedings that gave rise to the purchased power expenses in controversy in this case arose out of Petitioner's decision in 1986 to deal with offers from facilities qualifying under § 210 of PURPA[1] by conducting a competitive solicitation. It made this decision because it was receiving offers in amounts greater than its needs for the foreseeable future. Petitioner initiated its solicitation process in December 1986 by sending letters to potential sellers, including Ultra Cogen Systems, Inc.,[2] at its request. Pet. App. 62a. The solicitation letter specified capacity and energy charges that reflected the projected costs of Petitioner's planned Chesterfield 7 unit. Pet. App. 141a.

Petitioner sought 700 MW of capacity from its 1986 solicitation and received bids of 5,083 MW in response. Pet. App. 58a. Ultra Cogen submitted proposals to sell power from nine projects. Ultra Cogen's proposals were rejected in March 1987 because the proposed price was excessive and Ultra Cogen was unwilling to accept certain terms and conditions. Petitioner offered to purchase energy only from Ultra Cogen. Pet. App. 62a. In June 1987, Petitioner signed contracts for seven other projects and 1,264 MW that were offered in the 1986 solicitation. Pet. App. 58a.

---

[1] The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 824a-3 (1988 & Supp. V 1993). Section 210 of PURPA requires utilities to purchase power from cogeneration and small power production facilities that meet the technical and ownership criteria developed by the Federal Energy Regulatory Commission (FERC). A facility that meets these criteria is deemed to be a "qualifying facility" or QF.

[2] Ultra Cogen Systems, Inc., was succeeded in interest by Hadson Power and later by LG&E Development. The QF and the contracts at issue in this case were referred to as both Ultra Cogen and Hadson in the proceedings below. They will be referred to as Ultra Cogen in this brief.

In October 1987, the Virginia State Corporation Commission (VSCC) initiated a generic review of competitive bidding and its compliance with § 210 of PURPA. Pet. App. 63a. Between November 12, 1987, and December 3, 1987, while the VSCC's generic review was underway, Ultra Cogen filed petitions with the VSCC asking it to order Petitioner to enter into power purchase agreements that included payments for capacity. Ultra Cogen's first petition for arbitration involved a proposed cogeneration facility at The Lane Company, Inc. (Lane), in Altavista, Virginia. The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result. App. 6a-7a; Pet. App. 63a-64a.

On January 29, 1988, the VSCC issued its policy statement on competitive bidding, concluding that federal law did not require a utility to pay full administratively-determined avoided costs and that avoided costs could be determined through competitive bidding. The VSCC's policy statement went on to provide that, in evaluating specific proposals, favorable weight should be assigned to the use of Virginia fuels, manpower, and other state resources; the benefits to be derived by the industries and communities associated with particular projects; and other identifiable economic and societal benefits to the people of Virginia. Pet. App. 63a.

By order dated February 26, 1988, the VSCC rejected Petitioner's requested dismissal of Ultra Cogen's petitions on the ground that the VSCC had approved the use of competitive bidding. The VSCC decided that it would arbitrate Ultra Cogen's petitions and designated Commissioner Thomas P. Harwood, Jr., to serve as arbitrator. Pet. App. 164a-168a.

On March 1, 1988, Petitioner initiated a second solicitation. Petitioner's position in the arbitration proceedings was that the prices resulting from its competitive bidding solicitations should be used to set prices for the Ultra Cogen contracts. The Virginia arbitrator disagreed. By memorandum issued on April 27, 1988, he required the contracts to be based on the costs of constructing and operating Petitioner's Chesterfield 7, as projected on the date the first petition for arbitration was filed. The memorandum further noted that Petitioner's position in other dockets had been that Chesterfield 7 could and should serve as a basis for its avoided cost calculations because that unit was intended to be the prototype of any new capacity to be built by Petitioner through the mid-1990's. Pet. App. 172a.

On May 27, 1988, the arbitrator issued his interim order establishing capacity and energy prices, along with other key terms and conditions, for four of Ultra Cogen's proposed projects. This order merely recited his previous conclusion that the pricing proposal be based on the costs of Chesterfield 7 and that consideration be given to the expected capacity factors of the plants. The $341/kW capacity price for the Ultra Cogen projects was stated in an appendix, without any explanation as to how it was derived. Ultra Cogen's energy prices were established based on the assumption that coal prices would increase in the future.[3] Pet. App. 179a.

On September 30, 1988, the arbitrator entered his final order requiring Petitioner to sign the contracts. This order expressly recognized that "the Agreements reflect negotiations and rulings based on the unique circumstances of these proceedings (including that they are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." Pet. App. 189a.

---

[3] Petitioner's fuel reports on file with the North Carolina Utilities Commission (NCUC) showed that from 1984 through 1987 the cost of coal was decreasing and that it had remained relatively stable up to the time of the NCUC's order. Pet. App. 65a.

Petitioner signed the contracts on October 7 and 8, 1988. It did not appeal the VSCC arbitration orders. During December 1988 and January 1989 Petitioner signed contracts for the projects resulting from its 1988 solicitation. Pet. App. 65a.

On February 13, 1990, Commissioner Harwood issued an order granting a certificate of public convenience and necessity to Doswell Limited Partnership (Doswell).[4] In this order, he stated that payments for the Doswell projects, which resulted from the 1986 solicitation, were based on the avoided costs of Chesterfield 7 and were reasonable. App. 19a-20a; Pet. App. 73a.

2. *The North Carolina Utilities Commission Proceeding*

On July 31, 1992, Petitioner filed an application with the NCUC for an increase in its North Carolina retail rates. During this proceeding, the NCUC's Public Staff advocated the disallowance of $1.39 million of the Ultra Cogen capacity payments, the amount allocated to North Carolina by which they exceeded Petitioner's avoided costs at the time Ultra Cogen filed its arbitration petitions.[5] Pet. App. 66a. With respect to Petitioner's pre-emption argument, the NCUC's order noted that PURPA provides that avoided cost rates may not exceed the

---

[4] *Doswell Limited Partnership*, 110 P.U.R.4th 273 (Va.St.Corp.Comm'n (1990). Doswell's predecessor in interest, Intercontinental Energy Corporation, was a QF. It had been selected in the 1986 solicitation and signed contracts for two plants. These contracts were assigned to Doswell. Doswell, as a nonQF, independent power producer subject to the Federal Power Act (FPA), 16 U.S.C. §§ 791-825u (1988 & Supp. V 1993), filed the contracts for approval by the FERC. They were approved in *Doswell Limited Partnership*, 50 FERC ¶ 61,251, 110 P.U.R.4th 261 (1990).

[5] The NCUC's order found (Pet. App. 36a) and Petitioner stipulated to the North Carolina Supreme Court that the Ultra Cogen contracts had not been filed with the NCUC at the time it issued its order on February 26, 1993.

incremental cost of alternatives and that they must be reasonable to consumers. The NCUC's order further noted that generating facilities that qualify under § 210 of PURPA (QFs) are exempt from the FPA and that Congress did not intend to divest state regulatory commissions of their ratemaking authority with respect to QF contracts. Pet. App. 66a-68a.

The NCUC compared the Ultra Cogen contracts with other, contemporaneous measures of avoided costs and concluded that the prices in the Ultra Cogen contracts exceeded Petitioner's avoided costs at the time the arbitration petitions were filed.[6] Pet. App. 72a-73a. The NCUC examined the facts surrounding Petitioner's 1986 solicitation and its results; the costs and capacity factors of the Doswell plants, which resulted from the 1986 solicitations; and the costs and capacity factors resulting from Petitioner's 1988 solicitation. The uncontroverted evidence showed that the 1986 solicitation used Petitioner's proposed Chesterfield 7 plant as its benchmark, and the evidence established that the bids came in "right at the benchmark price." Pet. App. 73a. The NCUC therefore concluded that the average annual capacity payments of $141/kW resulting from the 1986 solicitation more accurately reflected the costs of the Chesterfield 7 plant, as projected in 1987,[7] than the arbitrator's unsupported $341/kW capacity payments.[8] In addition, the NCUC noted that the

---

[6] The NCUC's order also noted that the Ultra Cogen payments were out of line with Petitioner's approved avoided costs rates in North Carolina at the time the Ultra Cogen contracts were executed. If those rates had been used, the Ultra Cogen capacity would have cost Petitioner $17 million instead of the $64 produced by the arbitrator's order. Pet. App. 73a.

[7] The contracts for the projects resulting from the 1986 solicitation, including the Doswell contracts, were signed in June 1987. App. 13a, Pet. App. 58a.

[8] The NCUC's order also discussed the capacity factors of the various projects it reviewed. Because Petitioner uses the plants with the cheapest energy costs first, similarity in capacity factors would eliminate any justification for higher capacity payments. The Ultra Cogen projects had an average capacity

Virginia arbitrator himself stated in a February 1990 order that payments for the Doswell projects, which resulted from the 1986 solicitation, were based on the avoided costs of Chesterfield 7 and were reasonable. The Doswell capacity payments were $146/kW, compared to the $341/kW for the Ultra Cogen projects. Pet. App. 73a. The NCUC then used the results of Petitioner's 1988 solicitation to *increase* the amount included in North Carolina retail rates because the contracts resulting from it were signed at approximately the same time as Ultra Cogen's. Pet. App. 76a.

The NCUC's order also stated that it was very clear from the record that the VSCC's treatment of the Ultra Cogen projects was directly related to expected benefits to Virginia from these projects, reciting the "unique circumstances" language from the arbitrator's final order and the economic development benefits to Virginia cited in Ultra Cogen's arbitration petition. The NCUC noted that these benefits flow to Virginia, not to North Carolina. The NCUC stated that it could not "find these expenses to be reasonable for our purposes when they are well over twice contemporaneous measures of avoided capacity costs and they were clearly influenced by economic benefits unique to the State of Virginia." Pet. App. 74-75a. For this reason, the NCUC concluded that while it may be reasonable for Virginians to pay the extra costs associated with the Ultra Cogen projects, it was not reasonable for North Carolinians to pay such extra costs. Pet. App. 74a.

3. *The North Carolina Supreme Court's Decision*

On appeal to the North Carolina Supreme Court, Petitioner argued that the NCUC's disallowance of $1.39 million in expenses for the capacity payments for the Ultra Cogen projects violated

---

factor of 27%, while the projects resulting from the 1986 and 1988 solicitations had combined capacity factors of 32% and 36%, respectively. Pet. App. 8a and 75a-76a.

PURPA and the Commerce Clause of the United States Constitution. In response to Petitioner's reliance on *Nantahala Power & Light Company v. Thornburg*[9] and *Mississippi Power & Light Company v. Mississippi ex rel. Moore*[10] to support its pre-emption arguments, the North Carolina Supreme Court noted that those cases address the pre-emptive effect of a rate or apportionment *set by the FERC* for a wholesale transaction subject to regulation under the FPA. The Court further pointed out that, under the FERC's regulations, the purchase price for power sold by QFs is exempt from regulation by the FERC, and the rates *are determined by the states* under the federal rules.

The North Carolina Supreme Court noted that under the express terms of § 210 of PURPA and the FERC's regulations, the purchase price for QF power cannot exceed avoided costs. Its opinion noted that the FERC's earlier position that the states were free, under their own authority, to approve rates higher than avoided costs had been reversed by the FERC in *Orange and Rockland Utilities*.[11] Pet. App. 5a.

The North Carolina Supreme Court concluded that the VSCC had to apply the avoided cost rule in determining the rates for the Ultra Cogen projects and held that, if the NCUC disallowed only that portion of the Ultra Cogen capacity payments that was *above* avoided costs, its disallowance did not violate PURPA (and therefore was not pre-empted). Pet. App. 6a. The court then examined the evidence to determine whether competent evidence supported the NCUC's finding that the price for capacity set by the Virginia arbitrator was unreasonably high compared to

---

[9] 476 U.S. 953 (1986).

[10] 487 U.S. 354 (1988).

[11] 43 FERC ¶ 61,067, 92 P.U.R.4th 1 (1988)(holding that it is impermissible for the states to impose rates exceeding avoided costs).

contemporaneous measures of Petitioner's avoided costs. The court's opinion recited the following evidence:

(1) The 1986 solicitation, which was based on the costs of Chesterfield 7, produced average capacity costs of $141/kW, compared to $341/kW for the Ultra Cogen projects. The 1986 projects were expected to operate at a 32.2 percent capacity factor compared to 27.1 percent for the Ultra Cogen projects, thus eliminating any justification for the higher capacity costs on the basis of lower energy costs. Pet. App. 7a-8a;

(2) The Virginia arbitrator himself stated in a February 1990 order that payments for the Doswell projects, which were offered by Doswell's predecessor in interest in the 1986 solicitation, were based on the avoided costs of Chesterfield 7 and were reasonable. The capacity costs for the Doswell projects were $146/kW, while the capacity costs for the Ultra Cogen projects were $341/kW. Furthermore, the Ultra Cogen projects' average capacity factor, based on economic dispatch, was approximately one-half that of the Doswell projects, which indicates the Ultra Cogen projects' energy costs are greater. Pet. App. 8a; and

(3) The seven projects that were selected in the 1988 solicitation and were operational at the time of the hearing have an average capacity cost of $171/kW and a combined capacity factor of 35.9 percent. The results of the 1988 solicitation were then used as a proxy for what the costs of Chesterfield 7 (and the 1986 solicitation projects) would have been at the time the Ultra Cogen contracts were signed. Using the results of the later solicitation did not prejudice Petitioner but rather allowed it to include $30/kW (or $240,000) more in rates. Pet. App. 8a.

Based on its review of the foregoing evidence, the North Carolina Supreme Court concluded that the NCUC's findings were supported by competent evidence. It therefore held that, because the NCUC's exclusion of the $1.39 million in expenses for

capacity payments to Ultra Cogen was nothing more than the disallowance of the amount by which the contract price exceeded Petitioner's avoided costs, there was no violation of PURPA. Pet. App. 10a.

REASONS WHY THE WRIT SHOULD NOT BE GRANTED

I. THE NORTH CAROLINA SUPREME COURT'S OPINION IS CONSISTENT WITH THIS COURT'S SUPREMACY CLAUSE DECISIONS.

A. Introduction

Petitioner argues that the North Carolina Supreme Court's decision conflicts with this Court's Supremacy Clause decisions and violates PURPA. Respondent will show that, because the NCUC order affirmed by the North Carolina Supreme Court disallowed only the portion of the Ultra Cogen capacity costs that exceeded Petitioner's avoided costs at the time the arbitration petitions were filed, it is consistent with § 210 of PURPA and the FERC's regulations. The North Carolina Supreme Court's decision therefore recognizes the supremacy of federal law and is in strict accordance with this Court's decisions.

B. This Court's Supremacy Clause Decisions and the Requirements of § 210 of PURPA

It is well-established that Congress has the power under the Supremacy Clause of Article VI of the Constitution to pre-empt state law. Determining whether Congress has exercised this

power requires an examination of congressional intent.[12] In the absence of explicit statutory language, this Court infers such intent in three specific situations: (1) where Congress has legislated comprehensively to occupy an entire field of regulation, leaving no room for the states to supplement federal law, *Rice v. Santa Fe Elevator Corporation*;[13] and (2) where the state law at issue conflicts with federal law, either because (a) it is impossible to comply with both, *Florida Lime & Avocado Growers, Inc. v. Paul*,[14] or (b) the state law stands as an obstacle to the accomplishment and execution of congressional objectives. *Hines v. Davidowitz*.[15]

Early in this century, this Court fashioned a bright line dividing permissible from impermissible state regulation. This Court, in *Missouri ex rel. Barrett v. Kansas Natural Gas Company*, held that the retail sale of natural gas was subject to state regulation, "even though the gas be brought from another State and drawn for distribution directly from interstate mains."[16] This Court further held that the wholesale sale of gas in interstate commerce was not subject to state regulation.[17] This wholesale/retail line was applied to the electric industry in *Public Utilities Commission v. Attleboro Steam & Electric Company*.[18]

---

[12] *E.g., Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375 (1983).

[13] 331 U.S. 218, 230 (1947).

[14] 373 U.S. 132, 142-143 (1963).

[15] 312 U.S. 52, 67 (1941).

[16] 265 U.S. 298, 309 (1924).

[17] *Id.* at 307

[18] 273 U.S. 83 (1927).

As a direct result of *Attleboro* and its predecessor cases, Congress established federal regulation over most of the wholesale transactions of electric and gas utilities by enacting the Federal Power Act (FPA)[19] and creating the Federal Power Commission (now the FERC) to carry out that regulation. The FPA defines the sale of electric energy at wholesale as "a sale of electric energy to any person for resale."[20]

This Court has consistently recognized that the regulation of utilities is one of the most important of the functions traditionally associated with the police power of the states.[21] With respect to areas claimed to have been pre-empted that have been traditionally occupied by the states, such as the regulation of utilities, this Court stated that "we start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress."[22]

The explicit language and the legislative history of the FPA indicate that Congress did not intend to supersede the regulatory powers of the states. To make this point clear, § 210(a) of the FPA[23] provides that federal regulation is to extend only to those matters that are not subject to regulation by the states. In addition, § 201(b)(1)[24] provides that, other than for a

---

[19] 16 U.S.C. §§ 791-825u (1988 & Supp V 1993).

[20] *Id.* § 824(d) (1988).

[21] *See Pacific Gas & Elec. Co. v. State Energy Resources Conservation & Dev. Comm'n*, 461 U.S. 190 (1983)(*Pacific Gas*); *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218 (1947)(*Rice*); *Munn v. Illinois*, 94 U.S. 113 (1877).

[22] *Pacific Gas*, 461 U.S. at 206 (1983), *quoting Rice*, 331 U.S. at 230.

[23] 16 U.S.C. § 824(a) (1988).

[24] *Id.* § 824(b)(1) (1988).

few exceptions not relevant here, Part II of the FPA does not apply to any sale of electric energy other than a sale at wholesale. This Court recently described this section as "the 'savings clause' of the [FPA], which reserves to the States the regulation of local retail rates."[25]

The legislative history of the FPA also supports the conclusion that retail ratemaking was reserved to the states. Congress intended that its legislation "tak[e] no authority from State commissions."[26] In addition, the limiting clause in § 201(a) of the FPA was viewed as protecting the states' regulation of local affairs, including rates for intrastate and interstate-for-consumption sales.[27]

The language and legislative history of § 210 of PURPA show no intention to change this reservation of authority in the states to regulate local retail rates. As discussed by this Court in *Federal Energy Regulatory Commission v. Mississippi*,[28] Congress enacted § 210, as part of a comprehensive package of energy legislation, to encourage certain nontraditional generating facilities to reduce this country's demand for traditional fossil fuels. Congress believed two problems impeded the development of these nontraditional facilities: (1) traditional electric utilities were reluctant to purchase power from and sell power to them and (2) regulation by federal and state utility authorities imposed financial burdens on them and thus discouraged their development.

To overcome the first of these perceived problems, § 210(a) of PURPA directed the FERC, in consultation with state

---

[25] *Wyoming v. Oklahoma*, 502 U.S. 437, 457 (1992).

[26] H.R.Rep.No. 1318, 74th Cong., 1st Sess., 8 (1935).

[27] H.R.Rep.No. 5423, 74th Cong., 1st Sess., 385 (1935).

[28] 456 U.S. 742, 750-51 (1982).

regulatory authorities, to promulgate "such rules as it determines necessary to encourage cogeneration and small power production."[29] To solve the second perceived problem, § 210(e) directed the FERC to prescribe rules exempting QFs from all or part of the FPA, from the Public Utility Holding Company Act of 1935 (PUHCA),[30] and from state public utility laws, if the FERC found such exemption to be necessary to encourage QFs.[31]

In § 210(b), Congress provided that the rate to be set by the FERC must (1) be just and reasonable to the electric consumers of the electric utility and in the public interest and (2) not discriminate against qualifying cogenerators or qualifying small power producers. It further provided that no rule prescribed under § 210(a) "shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."[32]

The FERC subsequently adopted regulations to implement § 210 of PURPA.[33] These regulations define "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from the QF, the electric utility would generate or construct itself or purchase from another source.[34] Electric utilities are required to purchase electricity from QFs at a rate equal to their full avoided costs.[35]

---

[29] 16 U.S.C. § 824a-3(a) (1988).

[30] 15 U.S.C. §§ 79 to 79z-6 (1988 & Supp V 1993).

[31] 16 U.S.C. § 824a-3(e) (1988 & Supp V 1993).

[32] *Id.* § 824a-3(b) (1988).

[33] 18 C.F.R. §§ 292.101-.602 (1995).

[34] *Id.* § 292.101(b)(6) (1995).

[35] *Id.* § 292.304 (1995).

The regulations further provide that QFs are exempt from all sections of the FPA (with the exception of several sections that are not relevant here), from PUHCA, and from state law or regulation with respect to the rates and the financial and organizational regulation of electric utilities.[36] In the preamble to its regulations, the FERC acknowledged explicitly that its rules were not intended to divest a state regulatory agency of its authority under state laws to review contracts for purchases as part of its regulation of electric utilities, as long as such authority is exercised consistently with § 201 of PURPA and the FERC's regulations.[37]

C. The Consistency of the North Carolina Supreme Court's Opinion With Federal Law

Petitioner concedes that the NCUC actions of which it complains were traditional retail ratemaking actions under state law.[38] Petition at 21. Petitioner also concedes that Congress, in enacting § 210 of PURPA, carved out an exception to the FERC's exclusive jurisdiction over wholesale interstate power transactions by exempting QFs from the FPA. Petition at 20. Petitioner thus has conceded that *Nantahala Power & Light Company v. Thornburg*[39] is not directly applicable. Rather it argues that, because the Virginia arbitrator was purporting to act pursuant to federal law, the NCUC is bound to adhere to his decision "just as though FERC itself had acted." Petition at 25. In addition,

---

[36] *Id.* § 292.601-.602 (1995).

[37] *Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, at 12,233 (1980)(*PURPA Regulations*).

[38] Petitioner further concedes that the NCUC did not attempt to change the contract between Ultra Cogen and Petitioner. Petition at 18 n.19.

[39] 476 U.S. 953 (1986).

Petitioner argues that the NCUC's retail ratemaking has "trapped" federally determined wholesale costs, just as in *Nantahala*.

Nantahala and *Mississippi Power & Light Company v. Mississippi ex rel. Moore*[40] address the pre-emptive effect of a rate or apportionment *set by the FERC* for a wholesale transaction subject to its regulation under the FPA. Because QFs are exempt from the FERC's ratemaking authority under the FPA and the authority to set avoided cost rates was delegated to the states, not only has the FERC not made a specific rate finding in this case, it has issued no opinion on it whatsoever.[41] Because there are no federally mandated payments or approved allocations of power, the NCUC, by disallowing state-determined avoided costs, did not attempt to revise a previous FERC decision, which makes the holding of *Nantahala* inapplicable.

Thus, Petitioner's entire argument rests on its unsupported contention that the Virginia arbitrator was acting in accordance with § 210 of PURPA and the FERC's regulations when he approved the Ultra Cogen contract prices. To the extent those prices exceed Petitioner's avoided costs, he could not have been acting pursuant to § 210 of PURPA because it explicitly "sets full avoided costs as the maximum rate that the [FERC] may

---

[40] 487 U.S. 354 (1988).

[41] Petitioner asserts that the FERC, in *Doswell Limited Partnership*, 50 FERC ¶ 61,251, 110 P.U.R.4th 261 (1990), impliedly affirmed the VSCC's Ultra Cogen decision. Petition at 23 n.32. Actually the FERC's decision merely noted that Doswell's assertion that Chesterfield 7 was an accurate representation of Petitioner's avoided costs was corroborated by the VSCC's adoption of the Chesterfield 7 costs as the standard by which to set avoided cost pricing for four QF projects during the same time period. The FERC did not imply, much less find, that the Ultra Cogen contract rates were actually based on Chesterfield 7. Pet. App. 150a.

prescribe."[42] In the preamble to its regulations, the FERC expressed its opinion that, while its rules were subject to the avoided cost cap, the states were free, under their own authority, to enact laws or regulations for rates higher than avoided costs. The FERC explicitly stated, however, that if a state program required utilities to purchase power from QFs at higher rates, the higher rates would be based on state authority, not on the FERC's rules.[43] Therefore, because the arbitrator approved avoided costs that exceeded Petitioner's avoided costs at the time the arbitration petitions were filed, he was acting pursuant to state law, not federal law, and the NCUC was not bound by his determination.[44]

The only support Petitioner offers for its position is that (1) the Virginia arbitrator stated he was establishing the contract prices as Petitioner's avoided costs and the NCUC cannot recast the Virginia arbitrator's decision from a federal mandate into a state action against the issuing state's wishes and (2) the NCUC and the North Carolina Court were "tellingly silent" on the FERC's regulation that establishes the date on which avoided costs must be determined. Petition at 26-27.

In support of its first contention Petitioner notes that the arbitrator's orders unequivocally state that he was establishing the

---

[42] *American Paper Inst. v. American Elec. Power Serv. Corp.*, 461 U.S. 402, 413 (1983).

[43] *PURPA Regulations*, 45 Fed. Reg. 12,214, at 12,221 (1980); *see Middle S. Serv.*, 33 FERC ¶ 61,408, at 61,788-89, 71 P.U.R.4th 580, 590 (1985). The FERC has subsequently reversed this position, holding that a state cannot impose a rate exceeding avoided costs on sales by QFs. *Orange & Rockland Util.*, 43 FERC ¶ 61,067, at 61,195, 92 P.U.R.4th 1, 15 (1988); *accord Connecticut Light & Power Co.*, 70 FERC ¶ 61,012, at 61,029 (1995).

[44] The issues of whether the FERC can pre-empt independent state authority and whether federal authority can be delegated to one state to make determinations that are binding on another state are not raised here because North Carolina strictly complied with § 210 of PURPA and the FERC's regulations.

contract prices as Petitioner's avoided costs in accordance with the FERC's regulations. Petitioner then argues that the arbitrator interpreted the FERC's regulations to require Ultra Cogen's prices to be based on administratively determined avoided costs and not on competitive bidding results. This argument has no merit for two reasons. First, the FERC in *Orange and Rockland* emphasized that whether a rate exceeds avoided costs is a factual question that is independent of whether the rate was *intended* to exceed avoided costs.[45] Secondly, in this particular case, avoided costs determined administratively and avoided costs determined through competitive bidding are the same. The evidence conclusively establishes that the administratively-determined avoided costs judged appropriate for use by the Virginia arbitrator (the costs of Chesterfield 7) and the average results of the 1986 competitive solicitation were the same.[46]

Even if the 1986 solicitation results were ignored, the arbitrator's own Doswell decision demonstrates that the Doswell projects were offered to Petitioner at about the same time as the Ultra Cogen projects and that the contract prices for the Doswell projects were based on the costs of Petitioner's Chesterfield 7 plant. In addition, these plants began selling power to Petitioner within a few months of one another (Doswell on May 3 and May 10, 1992, and Ultra Cogen on February 22, March 7, and July 1, 1992), and the Ultra Cogen projects' average capacity factor, based on economic dispatch, was approximately one-half that of

---

[45] *Orange & Rockland Util.*, 43 FERC ¶ 61,067, at 61,196, 92 P.U.R.4th 1, 16 (1988).

[46] As was discussed on pp. 7-8 of this brief, the NCUC found: (1) the 1986 solicitation used Petitioner's proposed Chesterfield 7 plant as a benchmark, (2) the bids came in at the benchmark price, and (3) the contracts were signed in June 1987. As a result, the NCUC concluded that the average annual capacity payments of $141/kW resulting from the 1986 solicitation more accurately reflected the costs of the Chesterfield 7 plant, as projected in 1987, than the arbitrator's unsupported $341/kW.

the Doswell projects, which indicated the Ultra Cogen projects' energy costs were greater. Pet. App. 8a. Thus, the arbitrator's own order establishes that the Ultra Cogen contracts with their $341/kW capacity costs and 27% average capacity factor exceeded the 1987 projected costs of Chesterfield 7. If Chesterfield 7 had actually been used as the basis for the rates set in the Ultra Cogen contracts, the Ultra Cogen projects' and the Doswell projects' capacity costs and factors would have been comparable.

Petitioner's arguments about the use of the results of the 1988 solicitation are equally unavailing. The NCUC simply used the 1988 results ($171 per kW) as a proxy for what the costs of Chesterfield 7 and the results of the 1986 solicitation would have been at the time the Ultra Cogen contracts were signed in late 1988. Using the results of the later solicitation did not prejudice Petitioner but rather allowed it to include higher capacity costs in rates.

The evidence therefore establishes conclusively that the NCUC used the same standard that the Virginia arbitrator found to be appropriate for the determination of Ultra Cogen's avoided cost rates and that the costs of Chesterfield 7, and, therefore, Petitioner's avoided costs, were no more than $171/kW, the amount allowed by the NCUC as reasonable expenses when it established Petitioner's retail rates. The NCUC in fact would have been justified in disallowing an even greater amount (i.e., the amount by which the Ultra Cogen contracts exceeded Doswell's $146/kW capacity costs or the $141/kW average capacity costs resulting from the 1986 solicitation).

Petitioner's second contention, that the NCUC and the North Carolina Supreme Court were "tellingly silent" on the interpretation of the FERC's regulation that establishes the date on which avoided costs must be determined, also is without merit. The relevant FERC regulation, 18 C.F.R § 292.304(d)(2), provides that each QF shall have the option of providing energy or capacity pursuant to a legally enforceable obligation over a

specified term, in which case the rates shall, at the option of the QF be based on either (i) the avoided costs calculated at the time of delivery or (ii) the avoided costs calculated at the time the obligation is incurred.

The preamble to the FERC's regulations indicates that § 292.304(b)(5) and subsection (d) were intended to reconcile the requirement that the rates for purchases equal the utilities' avoided costs with the need of QFs to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. The preamble further states that the use of the term "legally enforceable obligation" was used to prevent a utility from circumventing its purchase requirement by refusing to enter into a contract with a QF.[47] Thus, the FERC's purpose in promulgating this regulation was not to dictate the exact date at which avoided costs were to be measured, but rather to make it clear that a QF was entitled to a long-term contract with fixed rates based on the estimate of avoided costs at the time the contract was signed or the QF's obligation to provide power became legally enforceable. The arbitrator himself stated that the date the first arbitration petition was filed constituted the *latest* possible date on which Ultra Cogen became obligated to provide power to Petitioner. Pet. App. 172a.

In any event, as the uncontroverted evidence shows, the results of the 1986 competitive solicitation were equal to the costs of Chesterfield 7, as they were estimated in 1987. The evidence overwhelmingly supports the conclusion that Petitioner's avoided capacity costs in November 1987 were no greater than $171/kW. Moreover, the NCUC's disallowance, which leaves the amount in excess of avoided costs to be recovered in the state that imposed the excessive costs,[48] is consistent with the FERC's proposed

---

[47] *PURPA Regulations*, 45 Fed. Reg. 12,214, at 12,224 (1980).

[48] Virginia arguably is pre-empted from disallowing the purchased power expense resulting from the Ultra Cogen contracts because it set the contract rates. *See Pennsylvania Elec. Co.*, 89 P.U.R.4th 402 (Pa.Pub.Util.Comm'n 1988).

solution for multi-state, multi-utility integrated systems subject to its jurisdiction. The FERC declared, in its *Orange & Rockland* decision, that the states would no longer have the authority to approve rates for purchases from QFs in excess of the purchasing utility's avoided costs.[49] The FERC stated that, where a state had already imposed a rate exceeding avoided costs on purchases by a member of a multi-state, multi-utility integrated system, it would require the system to allocate the excessive costs to the utility in the state that imposed the excessive rate if necessary to prevent unfairness to customers in other states. The FERC further stated that localizing excessive costs is important to prevent subsidies.[50]

When the Petitioner's contentions are viewed in light of the uncontroverted evidence and the foregoing decisions, the conclusion is inescapable that the NCUC's actions not only did not violate PURPA or interfere with its goals or enforcement in any way, but rather were entirely consistent with PURPA and actually further its goals. In addition, contrary to Petitioner's claims, no costs have been "trapped." The amount in excess of avoided costs, and therefore not in accordance with federal law, is lawfully recoverable by Petitioner through its retail rates in Virginia, the state that imposed the rates in excess of avoided costs.

D. Conclusion

Each of Petitioner's arguments in support of its contention that the North Carolina Supreme Court's opinion is in conflict with this Court's Supremacy Clause decisions and in violation of PURPA has been demonstrated to be without merit. Contrary to Petitioner's arguments, *Nantahala* and *Mississippi Power* are not

---

[49] *Orange & Rockland Util.*, 43 FERC ¶ 61,067, at 61,195, 92 P.U.R.4th 1, 15 (1988). In support of its decision, the FERC stated that rates in excess of avoided cost had an adverse impact on utilities and consumers and that the QF industry had come of age and thus required no additional encouragement. *Id.*

[50] *Id.* at 61,196, 92 P.U.R.4th at 16.

applicable to this case because the FERC did not approve the rates at issue and would have disapproved them if it had had the opportunity.[51] There is no direct conflict between PURPA and state law in this instance because the North Carolina Supreme Court and the NCUC recognized the supremacy of federal law in determining Petitioner's retail rates by disallowing the capacity payments only to the extent they exceed avoided costs.

The evidence also shows that the Ultra Cogen capacity prices established by the Virginia arbitrator were premised on economic benefits unique to the State of Virginia. The NCUC's adjustment to Petitioner's expenses was nothing more than the disallowance of the amount in excess of avoided costs, which, under relevant case law, is recoverable through Petitioner's retail rates charged in Virginia.

There can be no conflict or inconsistency between a federal statute that prohibits payments to QFs in excess of avoided costs and a state retail ratemaking order that disallows recovery of only the excessive payments. Therefore, the decisions of the NCUC and the North Carolina Supreme Court are entirely consistent with this Court's Supremacy Clause decisions.

II. THE NORTH CAROLINA SUPREME COURT'S OPINION IS CONSISTENT WITH THE PURPOSES AND GOALS OF § 210 OF PURPA, AND ANY FEDERAL ISSUES INVOLVED IN THIS CASE ARE NOT OF CURRENT OR GENERAL INTEREST.

Petitioner alludes to three ways in which it believes the North Carolina Supreme Court's decision in this case undermines § 210 of PURPA, thereby raising important federal issues. None of these has any merit.

---

[51] *See id.*

Petitioner's first contention is that appropriate and fair implementation of PURPA is essential because so much of this country's electricity production capacity is now being supplied through alternative suppliers. Petition at 17. This development, however, does not mean that these alternative suppliers are QFs seeking to take advantage of § 210 of PURPA. Future generation from QFs actually is expected to decline in importance because of the recent passage by Congress of the Energy Policy Act of 1992 (EPACT).[52] In fact, § 210 of PURPA is now the subject of repeal efforts before Congress.[53]

The EPACT is a comprehensive package of legislation that includes amendments to PURPA, the FPA, and PUHCA for the purpose of encouraging more competition in the generation segment of the electric power industry. For example, before the EPACT's amendments, PUHCA prevented a vertically-integrated utility from selling power from facilities disintegrated from the rest of its power system, and it discouraged the entry of independent power producers (i.e., wholesale, nonrate-based generating facilities) except for the exempted QFs. Because the new PUHCA removes a major constraint on the development of nonQFs, competitive power procurement mechanisms are expected to become the standard industry practice, which in turn will lead to a decline in the importance of future generation from QFs.[54]

---

[52] Pub. L. No. 102-486, 106 Stat. 2776 (codified as amended in scattered sections, chiefly 15, 16, and 42 of U.S.C.).

[53] *See* S. 708, 104th Cong., 1st Sess. (1995)(bill to repeal PURPA § 210, 16 U.S.C. § 824a-3).

[54] National Regulatory Research Institute, *A Synopsis of The Energy Policy Act of 1992: New Tasks for State Public Utility Commissions* 38 (1993); *cf. Connecticut Light & Power Co.*, 70 FERC ¶ 61,012, at 61,029 (1995)(states setting rates above avoided costs runs counter to Congress' and the FERC's policies of strongly favoring competition among all bulk power suppliers).

Petitioner's second contention is that disputes over the prices paid to suppliers must be fairly resolved to ensure that PURPA's goals are fulfilled, citing several cases that involve the issue of whether a utility or a state regulatory commission may change the price in a previously approved QF contract. Petition at 17. This case, however, does not involve any attempt to change the price paid to the QF. In fact, Petitioner concedes that the NCUC's action did not change the price the QF receives. Petition at 18 n.19. The only issue this case presents is whether a state regulatory commission can disallow in retail rates the amount by which the rate in a QF contract exceeds avoided costs, the excess of which was approved pursuant to state law rather than federal law. Thus, the cases cited by the Petitioner in its footnote 19 are irrelevant to this case.

The Petitioner's third contention is that regulatory decisions made under PURPA must be immune from collateral attack in order not to undermine federal law. Petition at 19. This issue also is not raised by this case. Federal law has not been undermined by North Carolina's recognition of the limitations imposed by § 210 of PURPA and the FERC's regulations. Indeed, North Carolina fully acknowledged the supremacy of federal law by disallowing for retail ratemaking purposes *only* the amount by which the Ultra Cogen contract prices exceeded Petitioner's avoided costs.

In summary, the North Carolina Supreme Court's decision does not undermine § 210 of PURPA, but rather is fully consistent with it and the FERC's regulations. In addition, because of the current Congressional policy of strongly favoring competition among all wholesale power suppliers, as reflected in the passage of the EPACT, future generation from QFs is expected to decline in importance. Therefore, any federal issues that may be involved in this case are not of current or general interest.

III. THE NORTH CAROLINA SUPREME COURT'S OPINION IS CONSISTENT WITH THIS COURT'S COMMERCE CLAUSE DECISIONS.

It has long been established that, even in the absence of pre-empting Congressional legislation, the Commerce Clause contains an implied limitation on the power of the states to interfere with or impose burdens on interstate commerce.[55] This Court has further stated that the general trend in its "modern Commerce Clause jurisprudence [is] to look in every case to 'the nature of the state regulation involved, the objective of the state, and the effect of the regulation upon the national interest in the commerce.'"[56]

In *Arkansas Electric*, this Court formally rejected the wholesale/retail approach to Commerce Clause issues and adopted the balance-of-interests approach it had formulated in prior Commerce Clause cases, noting that "[t]his modern jurisprudence has usually, although not always, given more latitude to state regulation than the more categorical approach of which *Attleboro* is one example."[57]

This Court further stated that the appropriate test to apply is:

> "Where [a] state statute regulates evenhandedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental,

---

[55] *See Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n.*, 461 U.S. 375, 389 (1983)(*Arkansas Electric*), *quoting Western & S. Life Ins. Co. v. Board of Equalization*, 451 U.S. 648, 652 (1981).

[56] *Arkansas Electric*, 461 U.S. at 390, *quoting Illinois Natural Gas Co. v. Central Ill. Pub. Serv. Co.*, 314 U.S. 498, 505 (1942).

[57] 461 U.S. at 390.

> it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits. If a legitimate local purpose is found, then the question becomes one of degree. And the extent of the burden that will be tolerated will of course depend on the nature of the local interest involved, and on whether it could be promoted as well with a lesser impact on interstate activities."[58]

Petitioner contends that the North Carolina Supreme Court's opinion places a substantial burden on interstate commerce in violation of the Commerce Clause because it allows the trapping of costs by inconsistent regulations. Petition at 28. As previously discussed, there are no trapped costs involved in this case. The North Carolina Supreme Court's opinion disallows the Ultra Cogen capacity costs only to the extent they exceed avoided costs and are prohibited by federal law. The excess capacity costs approved by the Virginia arbitrator pursuant to state law are recoverable from Petitioner's Virginia ratepayers.

Petitioner also asserts that the North Carolina Supreme Court's decision plainly was intended to shield North Carolina electric customers from costs imposed pursuant to federal law, including the subsidization of North Carolina ratepayers. Petition at 28-29. Respondent Public Staff has shown that the disallowance upheld by the North Carolina Supreme Court was nothing more than the disallowance of costs in excess of avoided costs (i.e., prohibited by federal law), and therefore it constituted lawful retail ratemaking.

Despite Petitioner's claims to the contrary, the evidence in this case amply demonstrates that North Carolina was not motivated by economic protectionism. The uncontroverted

---

[58] *Id.* at 393-94, *quoting Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970).

evidence demonstrates that the Virginia arbitrator's treatment of the Ultra Cogen projects was directly related to expected economic benefits to Virginia from these projects. Thus, the North Carolina Supreme Court's decision does nothing more than effectuate the legitimate local public interest of establishing just and reasonable retail rates by excluding the costs in excess of Petitioner's avoided costs. It therefore prevents those excessive costs, which were incurred pursuant to Virginia law for the benefit of Virginia, from being shifted to Petitioner's North Carolina ratepayers. The North Carolina Court's decision, therefore, has no more effect on interstate commerce than any other aspect of retail ratemaking for a utility that operates in more than one state. Almost all retail ratemaking would be a direct, and therefore unlawful, burden on interstate commerce under Petitioner's reasoning, contrary to this Court's conclusion in *Arkansas Electric* that "the national fabric does not seem to have been seriously disturbed by leaving regulation of retail utility rates largely to the States."[59]

The Eighth Circuit decision cited by Petitioner, *Middle South Energy v. Arkansas Public Service Commission*,[60] involved a multi-state, multi-utility integrated system, and the issue in controversy was one over which the FERC has exclusive ratemaking jurisdiction. In that respect, *Middle South* is more like *Nantahala* than the case currently before the Court. In fact, *Middle South* involved a continuation of the controversy over the Grand Gulf nuclear plant, of which *Mississippi Power* was a part.

The disallowance upheld by the North Carolina Supreme Court was nothing more than the disallowance of costs in excess of avoided costs, and therefore it constituted lawful retail ratemaking. Given the North Carolina Court's recognition of the requirements of § 210 of PURPA, Petitioner's Commerce Clause contentions are totally without merit.

---

[59] 461 U.S. at 395.

[60] 772 F.2d 404 (8th Cir. 1985), *cert. denied*, 474 U.S. 1102 (1986).

CONCLUSION

This Court should deny the petition for a writ of certiorari. This case presents no conflicts with this Court's decisions and does not raise federal issues of current or general interest.

Respectfully submitted,

GISELE L. RANKIN*
A. W. TURNER, JR.
Public Staff - NCUC
430 North Salisbury Street
Raleigh, North Carolina 27611
(919) 733-6110

Counsel for the Public Staff

* Counsel of Record

APPENDIX

CONTENTS OF APPENDIX

Page

APPENDIX A

Additional Statutory and Regulatory Provisions 1a

APPENDIX B

Petition of Ultra Cogen Systems, Inc.
for Arbitration (November 12, 1987) 5a

APPENDIX C

Opinion and Final Order of the Virginia State
Corporation Commission (February 13, 1990) 11a

APPENDIX A

Additional Statutory and Regulatory Provisions

The Federal Power Act, 16 U.S.C.A. § 824(a) (1988).

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation relating to generation to the extent provided in . . . this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

The Federal Power Act, 16 U.S.C.A. § 824a-3(b) (1988).

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase-

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

The Federal Power Act, 16 U.S.C.A. § 824a-3(e)(1) (1988).

Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, . . . prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C.A. § 791a et seq.], from the Public Utility Holding Company Act [15 U.S.C.A. § 79 et seq.], from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

The Federal Power Act, 16 U.S.C.A. § 824(b)(1) (1985).

The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but. . . shall not apply to any other sale of electric energy. . .

Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. § 292.101(b)(6) (1995).

(b) *Definitions*. The following definitions apply for purposes of this part.

(6) *Avoided costs* means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. § 292.304(d)(2) (1995).

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. § 292.601(a)-(c) (1994).

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b) of this section.

(b) *Exclusion.* This section does not apply to a qualifying small power production facility with a power production capacity which exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

(c) *General rule*. Any qualifying facility described in paragraph (a) of this section shall be exempt from all sections of the Federal Power Act, except:

(1) Section 1-18, and 21-30;
(2) Sections 202(c), 210, 211, 212, 213, and 214;
(3) Sections 305(c); and
(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (c)(1), (2) and (3) of this section.

APPENDIX B

**Petition of Ultra Cogen Systems, Inc.
for Arbitration (November 12, 1987)**

VIRGINIA:

BEFORE THE STATE CORPORATION COMMISSION

At Richmond

Petition of	)	
	)	Case No. PUE87____
ULTRA COGEN	)	
SYSTEMS, INC.	)	

PETITION FOR ARBITRATION

Ultra Cogen Systems, Inc. ("UCS"), developer and owner of a qualifying cogeneration facility to be located at The Lane Co. Inc. ("Lane"), in Altavista, Virginia, having conferred and been unable to reach an agreement with Virginia Electric and Power Company ("Virginia Power") for the sale and purchase of power, hereby petitions the Commission, pursuant to its final order dated January 11, 1983, in Case No. PUE800102, to institute an arbitration proceeding to determine the terms and conditions of a power purchase agreement ("Agreement"). In support thereof, UCS states that:

1. By Letter of Intent dated November 11, 1987, Lane and UCS agreed to work jointly to develop a cogeneration project at

the Lane plant in Altavista, Virginia.[1] The project will be a qualifying cogeneration facility ("the Facility") with a maximum name plate rating of 66,500 kw, at 13.8 kv and 0.85 power factor. UCS will design, construct, own, and operate the Facility for an initial term of 15 years. UCS will provide 45,000 pounds of steam per hour on an average annual basis to Lane.[2] The Facility will burn coal which is expected to come from or be transloaded in Virginia.

2. UCS' parent, Ultrasystems, Inc. ("Ultrasystems"), has considerable experience in the design, construction, and operation of power plants. Specifically, it designs, construction and operates new, advanced technology, fluidized-bed power plants, wood-fired power plants and coal-fired plants and is a high-technology engineering and development company engaged in the development, engineering, construction, ownership and operation of electrical power generation facilities. In fact, Ultrasystems is a leader in the alternative energy, cogeneration and advanced power generation industries. It also is actively involved in numerous defense and space systems projects, with particular emphasis on command, control, communications and intelligence programs and space systems. Ultrasystems' revenues were $155.1 million for the fiscal year ended January 31, 1987 and it had a contract backlog of $304 million as of July 31, 1987.[3]

---

[1] A copy of the Letter of Intent between Ultra Cogen Systems, Inc. and Lane is attached as Appendix A.

[2] An application for qualifying status has been filed with the Federal Energy Regulatory Commission. A copy of the application is attached hereto as Appendix B.

[3] On October 30, 1987, Ultrasystems and Hadson Corporation of Oklahoma City, Oklahoma announced that the Board of Directors of both companies approved a letter of intent to merge Ultrasystems and Hadson, Forming a coast-to-coast independent gas and electric company. The companies are expected to produce total revenue of more than $550 million in 1987.

3. Lane has operated its plant in Altavista, Virginia for 75 years. The plant produces fine cedar chests, tables and accent pieces. The plant employs 1,200 persons and annual sales from the plant total $100 million. Its ability to continue to operate at current levels depends upon the availability of reliable and economically priced steam, which will be provided by the Facility. The UCS and Lane cogeneration project, which will result in approximately $60 million being invested in the Altavista area, is of critical importance to the future economic health of Lane and the City of Altavista. Further, jobs and economic benefits to the community and the Commonwealth will result from the investment in and requirements of the Facility, including but not limited to the operation, maintenance and fueling of the Facility.

4. In its Final Order dated November 15, 1985, in Case No. PUE830067, Application of Virginia Electric and Power to revise Rate Schedule 19 - Power Purchases from Cogeneration and Small Power Production Qualifying Facilities, the Commission held ". . . [t]hat Schedule 19 must be revised to provide QFs [with a design capacity of 100 kw or less] the option of contracting for payments based on projected avoided energy costs either at the time the contract is executed or at the time power is delivered." 1985 SCC Ann. Rpt. 384, 390. The same options are available under regulations adopted by the Federal Energy Regulatory Commission for all QFs, including those with a design capacity in excess of 100 kw. 18 C.F.R. § 292.304(d) (2) (i) - (ii).

5. Under 18 C.F.R. § 292.303(a), Virginia Power is obliged to purchase power from UCS. Under 18 C.F.R. § 292.304, UCS is entitled to contract to sell such power at Virginia Power's long-term avoided capacity and avoided energy costs. Virginia Power has failed and refuses to contract for energy and capacity as and at the rates required by law. Such failure and refusal has been manifested (a) initially, in its proposal (and refusal to modify through negotiation) of rates and terms and conditions, which may be unfinanceable and (b) later, in its private and public refusals to negotiate on any terms or at any price.

6. UCS has expended substantial time and money in reliance on (a) Virginia Power's obligation to negotiate and (b) existing procedures and rates. Virginia Power has failed and refuses to negotiate pending anticipated revision of such procedures and rates. Further delay will unduly prejudice UCS and Lane and serve no legitimate purpose.

Accordingly, UCS respectfully submits for arbitration the following list of issues and requests that such arbitration occur forthwith and without regard to any anticipated revisions to procedures and/or rates:

A. Capacity and Energy Prices

(1) What is the appropriate rate and method of payment for long-term energy purchased from the Facility?

(2) What is the appropriate rate and method of payment for the long-term capacity purchased from the Facility?

(3) What other payments should be made by Virginia Power to UCS?

B. Terms and Conditions

(1) What is an appropriate dependability requirement for the Facility to receive full avoided cost capacity payments?

(2) Under what conditions, if any, should Virginia Power be entitled to refuse to receive and/or pay for power from the Facility?

(3) What should be the appropriate term of the Agreement, and what, if any, obligations should UCS have to repay amounts paid by Virginia Power in the event of termination of the Agreement prior to completion of its term?

(4) What, if any, security should be required for UCS' obligations under (3), above?

(5) To what extent, if any, should amounts payable pursuant to A(2) above be reduced by virtue of Facility outages or failure to meet projected output levels?

(6) What, if any, penalties or damages should UCS be required to pay for:

(a) failure to complete the Facility on schedule?

(b) failure of the Facility to produce electrical power at projected output levels?

(7) What, if any, security should UCS be required to provide for:

(a) its obligation to complete the Facility on schedule?

(b) its obligations under the Agreement after completion of the Facility?

(8) What obligations should Virginia Power have to interconnect the Facility to its system, and what, if any, obligations should UCS have to reimburse Virginia Power for the cost thereof?

(9) What should be the obligations of the parties in the event of (a) force majeure, (b) changes in law, or (c) regulatory action inconsistent with the terms or assumptions of the Agreement?

(10) What, if any, obligation should UCS have to reimburse Virginia Power for taxes incurred as a result of the transactions and activities contemplated by the Agreement?